BART Analysis for
PSNH Merrimack Station Unit MK2

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1. INTRODUCTION

PSNH Merrimack Station has two coal-fired steam-generating boilers that operate nearly full time to meet baseload electric demand. Unit MK2 is a wet-bottom, cyclone-type boiler with a heat input rating of 3,473 MMBtu/hr and an electrical output of 320 MW. Installed in 1968, this generating unit is equipped with selective catalytic reduction to remove oxides of nitrogen (NO_X) formed during the combustion process. Two electrostatic precipitators operate in series to capture particulate matter (PM) in the flue gases. Also, construction is nearing completion on a limestone forced oxidation scrubber system that will reduce sulfur dioxide (SO_2) emissions. Retrofit options for this unit are limited because the facility already has controls in place for these major pollutants of concern. Only a few emission control technologies are compatible with the type of boiler design employed, and space for new retrofits is very limited.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

Because of the current boiler design, the only NO_X emission control technology options available and potentially applicable to Unit MK2 are selective non-catalytic reduction and selective catalytic reduction.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on coal-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls for SNCR and SCR at Merrimack Station Unit MK2 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit (EGU) the size of Unit MK2. For SNCR, the total annual cost is estimated to be about \$5,110,000, or \$593/ton of NO_X removed. For an SCR system, the total annual cost is estimated to be \$5,070,000, or \$312/ton. Stated costs are for year-round operation.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	$	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
SNCR	12.1	3,880,000	4,780,000	5,110,000	593
SCR	117.8	37,710,000	1,910,000	5,070,000	312

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and 2,243 million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on an estimated 8,613 tons of NO_X removed for SNCR and an estimated 16,269 tons of NO_X removed for SCR.

Because Unit MK2 already has SCR controls in place, the listed costs serve for comparative purposes only. In 1998, PSNH estimated that its SCR costs would be about \$400/ton for year-round operation and about \$600/ton for operation limited to the ozone season (May 1 through September 30). These costs are approximately equal to \$530/ton and \$790/ton, respectively, in 2008 dollars. PSNH currently operates Unit MK2 full time in order to meet NO_X RACT requirements.

Year-round operation is EPA's presumptive norm for BART (applicable to EGUs of 750 MW capacity or greater) for units that already have seasonally operated SCRs. Assuming that operating costs are proportional to operating time, the difference in cost between year-round and seasonal SCR operation for Unit MK2 is about \$3,300,000, based on PSNH's 1998 cost estimates. The cost differential could be about half that amount, if based on the more recent generic estimates presented in Table 2-1.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome additional pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy. (In the case of Unit MK2, the existing fan was sufficient to accommodate the additional pressure drop.)

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit MK2 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag.

The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit MK2. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. Estimated PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	23.3-62.1 million	1.1-1.9 million	3.0-7.1 million	100-240
Wet ESP	73-194	23.3-62.1 million	0.6-1.6 million	2.6-6.8 million	90-230
Fabric filter – reverse air	82-194	26.4-62.1 million	1.6-2.4 million	3.8-7.6 million	130-260
Fabric filter – pulse jet	58-194	18.6-62.1 million	2.2-3.1 million	3.7-8.3 million	130-280

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 320-MW unit with 80% capacity factor and flue gas flow rate of 1.36 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 29,850 tons of PM removed for ESPs and 29,759 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $2.6 million to $8.3 million, or $90 to $280 per ton of PM removed. Because Unit MK2 already has two dry ESPs installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of $10,000 to $30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit MK2 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to "scrub" or "wash" unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources," March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule).

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Coal

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. Usually, for operational reasons, a facility cannot make a complete switch from one fuel type to another. Instead, the facility may be able to blend different fuels to obtain a lower-sulfur mix that emits less SO_2 upon combustion – for example, blending low-sulfur bituminous or subbituminous coal with a high-sulfur bituminous coal. The feasibility of fuel switching or blending depends on the physical characteristics of the plant (including boiler type), and significant modifications to systems and equipment may be necessary to accommodate the change in fuels. Switching to a lower-sulfur coal can affect coal handling and preparation systems, ash handling systems, boiler performance, and the effectiveness of PM emission controls. To meet federal acid rain requirements, many facilities have switched to lower-sulfur coals, resulting in SO_2 emission reductions of 50 to 80 percent.

2.3.1 Potential Costs of SO_2 Controls

PSNH Merrimack Station is required by New Hampshire law to install an FGD system to reduce mercury emissions (with SO_2 removal as a co-benefit) at both Unit MK1 (not a BART-eligible unit) and Unit MK2 (a BART-eligible unit). A company estimate for the project placed the capital cost at $457 million, or $1,055/kW (both amounts in 2008$) to install a wet limestone FGD system. Using 2002 baseline emissions of 30,657 tons of SO_2 from Units MK1 and MK2 combined, and a minimum capture efficiency of 90 percent for this pollutant, the annualized capital cost translates to about $1,400 per ton of SO_2 removed.

The project cost is said to be in line with the costs of multiple-unit scrubber installations occurring elsewhere in the country. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

The costs of switching to lower-sulfur coal at PSNH Merrimack Station would rest on the incremental cost of purchasing the lower-sulfur material at prevailing market prices. Even if a lower-sulfur coal is available at reasonable additional cost, operational considerations related to the physical characteristics of Unit MK2 may dictate the choice of coal for this unit. (Only certain types of coal can be used in wet-bottom, cyclone boilers; and lower-sulfur coals have already been tested and adopted for regular use at this facility.) Commodity spot prices for coal vary considerably. For example, from late March to early May 2009, the price spread between Northern Appalachia coal (<3.0 SO_2) and Central Appalachia coal (1.2 SO_2) ranged from $10 to $25 per ton (source: Energy Information Administration, http://www.eia.doe.gov/fuelcoal.html).

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

In 1994, PSNH installed an SCR system on Unit MK2, the first such system to be used on a coal-fired, wet-bottom, cyclone boiler in the United States. The SCR was designed to meet NO_X Reasonably Available Control Technology (RACT) limits. Specifically, Unit MK2 is subject to a NO_X RACT Order limit of 15.4 tons per calendar day and a second NO_X RACT Order limit of 29.1 tons per calendar day for combined emissions from Units MK1 and MK2. The facility must also meet a less stringent federal acid rain program limit of 0.86 lb NO_X/MMBtu. PSNH has a monetary incentive to surpass the NO_X RACT requirements because further emission reductions allow the utility to accumulate DERs. Actual NO_X emissions for Unit MK2 were reported as 2,871 tons in baseline year 2002.

Since January 2001, the SCR on Unit MK2 has reduced NO_X emissions to between 0.15 and 0.37 lb/MMBtu (calendar monthly average), with a few excursions outside this range. (Note that the existing NO_X RACT limit of 15.4 tons per calendar day is mathematically equivalent to 0.37 lb/MMBtu.) Data available from the period of 1993 to early 1995, prior to operation of the SCR, provide a baseline for uncontrolled NO_X emissions in the range of 2.0 to 2.5

lb/MMBtu. Taken together, this information indicates that Unit MK2 achieves a control level that exceeds 85 percent most of the time and frequently surpasses 90 percent.

3.2 Discussion of Current PM Emissions and Controls

PSNH Merrimack Station Unit MK2 has two electrostatic precipitators (ESPs), dry type, operating in combination with a fly ash reinjection system. The ESPs have been upgraded with state-of-the-art electronic controls. Installation of the ESPs has reduced PM emissions from this unit by about 99 percent, based on a review of 2002 emissions data. The current air permit for the facility requires that Unit MK2 meet a total suspended particulate (filterable TSP) limit of 0.227 lb/MMBtu and a TSP emissions cap of 3,458.6 tons/year. However, the 0.227 lb/MMBtu rate does not reflect the true capabilities of the ESPs to control particulate emissions. Stack testing on three separate dates in 1999 and 2000 found actual TSP emissions to be 0.043, 0.041, and 0.021 lb/MMBtu after controls. The most recent test, in May 2009, produced an emission rate of 0.032 lb/MMBtu. Total TSP emissions from this unit were 210 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

New Hampshire law requires PSNH Merrimack Station to install and operate a scrubber system for both Unit MK1 and Unit MK2 by July 1, 2013. While the primary intent of this law is to reduce mercury emissions from the company's coal-fired power plants, a major co-benefit is SO_2 removal. Pursuant to this statutory obligation, New Hampshire issued a permit to PSNH on March 9, 2009, for the construction of a wet, limestone-based FGD system to control mercury and SO_2 emissions at Merrimack Station. The permit requires an SO_2 control level of at least 90 percent for Unit MK2. The specific language of the permit states as follows:

> Beginning on July 1, 2013,…SO_2 emissions shall be controlled to 10 percent of the uncontrolled SO_2 emission rate (90 percent SO_2 removal)…The Owner shall submit a report no later than December 31, 2014 that includes the calendar month average SO_2 emission rates at the inlet and outlet of the FGD and the corresponding calendar month average emissions reductions during the preceding 12 months of operation,…DES will use this data to establish the maximum sustainable rate of SO_2 emissions reductions for MK2. The maximum sustainable rate is the highest rate of reductions that can be achieved 100 percent of the time...This established rate shall be incorporated as a permit condition for MK2. Under no circumstances shall the SO_2 removal efficiency for MK2 be less than 90 percent.

These permit conditions effectively require that actual SO_2 removal efficiencies *exceed* 90 percent on average for Unit MK2. This plant must also meet general regulations for coal-burning devices that limit the sulfur content of the coal to 2.0 pounds per million BTU gross heat content averaged over any consecutive 3-month period, and 2.8 pounds per million BTU gross heat content at any time. Since 2002, the facility has operated well within these fuel limits. More specifically, PSNH has worked to control coal sulfur content to reduce SO_2 emissions and minimize the purchase of SO_2 allowances. Because the particular boiler design does not permit the burning of straight low-sulfur coal, the company blends coals to bring average sulfur content to a level that is consistent with sustainable boiler operations.

PSNH must also meet a fleet-wide SO_2 emissions cap of 55,150 tons/year effective for all electrical generating units at its Merrimack, Newington, and Schiller Stations. In 2002, actual SO_2 emissions from Unit MK2 were 20,902 tons.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Merrimack Station Unit MK2 was built in 1968. PSNH's commitment to install new emission controls on this unit demonstrates the company's belief that this unit is capable of supplying electricity to the region for many years beyond the present.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

5.1 CALPUFF Modeling Analysis

The New Hampshire Department of Environmental Services (NHDES) conducted a CALPUFF modeling analysis to assess the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Visibility can be quantified using deciviews (dv), a logarithmic unit of measure to describe increments of visibility change that are just perceptible to the human eye. NHDES conducted a set of CALPUFF runs for Unit MK2 under controlled and uncontrolled conditions. Before considering the findings of this modeling work, it is useful to review the results of the BART eligibility modeling performed by the Mid-Atlantic/Northeast Visibility Union (MANE-VU).

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit MK2 produce theoretical CALPUFF worst-case impacts of 2.24 dv at Acadia National Park. EPA considers it acceptable to exempt sources when this form of conservative modeling indicates that a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit MK2 exceed all of these exemption levels.

The BART assessment modeling provides a comparison of visibility impacts from current allowable emissions with those from the post-control emission level (or levels) being assessed. Results are tabulated for the average of the 20% worst natural visibility (about 11.7 to 12.4 dv) and 20% worst baseline visibility (about 22.8 dv) modeled days at each nearby Class I area. For any pair of control levels evaluated, the difference in the level of impairment predicted is the degree of improvement in visibility expected.

Rather than use CALPOST to manipulate background deciview calculations, NHDES normalized CALPUFF modeling results and then applied predicted concentrations to a logarithmic best-fit equation to the actual observed $PM_{2.5}$-to-deciview relationship measured at Acadia NP, Great Gulf NWR, and Lye Brook NWR. Thus, CALPUFF was applied in a relative way using real observed data as the basis. At this point, a number of background visibility scenarios could be calculated from the resulting PM-extinction-to-deciview equation. In accordance with BART guidance, the natural visibility condition (about 7 dv) was used for exemption purposes, and 20% worst natural and 20% worst baseline visibility were used for assessment of BART control effectiveness. The CALPUFF-predicted visibility benefits from BART controls on 20% worst natural and 20% worst baseline visibility days are as follows:

Table 5-1. CALPUFF Modeling Results for Merrimack Station Unit MK2: Visibility Improvements from BART Controls

On the 20% Worst Natural Visibilty Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	1.07	0.83	**0.17**
NOx	Additional 25% with SCR upgrade	0.21	0.18	**0.10**
PM	90% with upgraded controls	0.16	0.12	**0.03**
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	90% with FGD	**0.26**	**0.20**	0.03
NOx	Additional 25% with SCR upgrade	**0.07**	**0.06**	0.03
PM	90% with upgraded controls	**0.07**	**0.05**	<0.01*

* below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

While the full impact of Unit MK2 was predicted to be as large as 2.24 dv at Acadia National Park under natural conditions, the predicted visibility benefit from a 90% reduction in sulfur emissions at Unit MK2 on the most visibility-impaired days is only 0.26 dv. At first this result may appear to be too low; however, on further examination, it is found that CALPUFF predicts the same amount of sulfate from Unit MK2 reaching Acadia under both best and worst visibility conditions. The difference is that there is greater than an order of magnitude more sulfate coming from other sources on the 20% worst visibility days, raising the background concentrations to much higher levels. Because the deciview scale is logarithmic, the same mass reduction of 0.259 $\mu g/m^3$ of sulfate from this one source results in wide differences in deciview impacts for different background visibility conditions at opposite ends of the range.

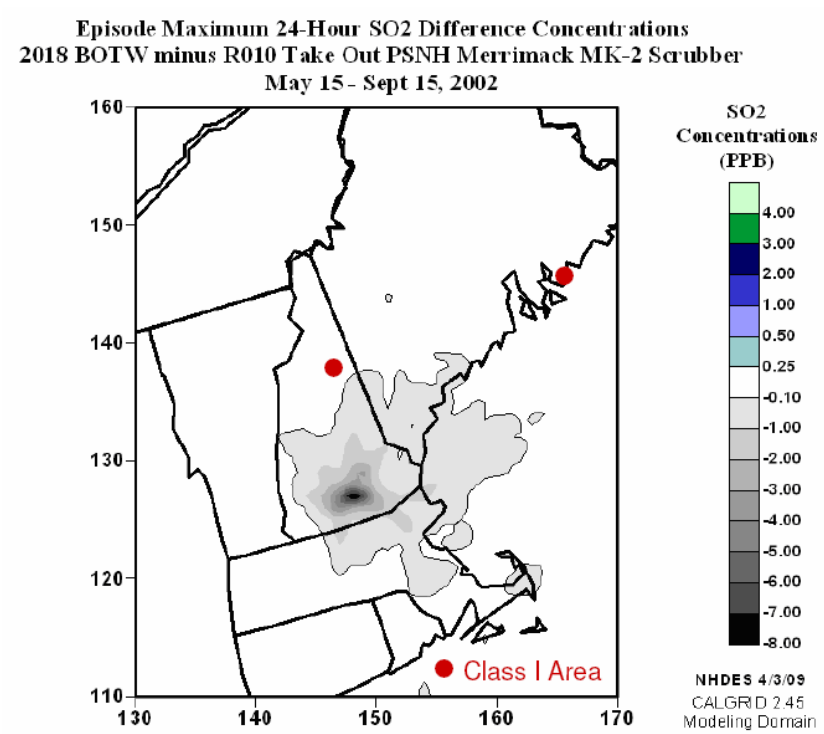
5.1 CALGRID Modeling Analysis

NHDES also conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Merrimack Station Unit MK2. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of installing an FGD system on Unit MK2. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) and used MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline. The BOTW emissions scenario reflects controls from potential new regulations that may be necessary to attain National Ambient Air Quality Standards and other regional air quality goals, beyond those regulations that are already "on the books" or "on the way."

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at nearby Class I areas (i.e., concentration impacts were converted to visibility impacts).

Based on the CALGRID modeling results, the installation of scrubber technology with 90% removal efficiency on Unit MK2 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by up to 21 $\mu g/m^3$ (8 ppb by volume; see Figure 5-1) and maximum predicted 24-hour average $PM_{2.5}$ concentration impacts by up to 1 $\mu g/m^3$. The largest modeled pollutant concentration reductions occur within a 50-kilometer radius of the facility. For the affected Class I areas (located 100 to 500 kilometers away), reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, are expected to yield a nominal improvement in visibility (about 0.1 deciview) on direct-impact hazy days.

Figure 5-1



NHDES's use of CALGRID differs somewhat from EPA's preferred methodology. CALPUFF is EPA's preferred model for performing long-range visibility assessments of individual sources to distant Class I areas, in part because it is considered to be a conservative model or one that is capable of estimating worst-case impacts rather than expected impacts. This makes CALPUFF ideally suited to screening BART sources for exemption purposes because it is likely to identify virtually all sources that could provide visibility benefits when their emissions are controlled.

CALGRID is a sister program to CALPUFF and shares much of the same chemistry; however, it works as a gridded model rather than a puff tracking model, and it has the advantage of easily tracking 20% worst visibility days and cumulative impacts by modeling all source sectors. NHDES chose to use CALGRID for screening since it is much easier to track the dynamics of impacts from single sources to multiple Class I areas on targeted days, rather than just applying the maximum impact conditions that may or may not be associated with 20% worst days. While the CALPUFF model's CALPOST post-processor has an option for application on 20% worst natural visibility days, it does not in fact isolate those 20% worst natural visibility days for analysis. It simply changes the background values the model uses to adjust what it estimates to be appropriate background levels. It does not account for wind directions that may be preferentially included or excluded on such days.

The above analyses indicate that CALPUFF and CALGRID have aligned better in their predictions than might be expected. This result may be attributed to the similar chemistry used in both models and to the specific circumstances of this case in which the prevailing wind direction on the 20% worst visibility days carries Unit MK2 emissions directly toward Class I areas such as Acadia National Park. The big discrepancy occurs under best visibility days, when CALGRID (correctly) does not align the source to receptor, but CALPUFF (incorrectly) applies wind directions for worst visibility days to the best day calculations.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Merrimack Station Unit MK2, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

PSNH currently operates an SCR system on Unit MK2. This system was installed in 1994 to meet the requirements of NO_X RACT and the ozone season NO_X budget program. SNCR is the only other control technology available for controlling NO_X emissions from this unit. SCR yields higher NO_X removal rates and is more cost-effective than SNCR. For units that already have seasonally operated SCRs, year-round operation is EPA's presumptive norm for BART. PSNH estimated, in 1998, that the existing SCR system could be operated year-round at a cost of \$494 per ton of NO_X removed.

For an early-generation SCR that has received previous retrofits to improve its performance, further upgrades to this NO_X control system appear to be impractical and would yield negligible (generally less than 0.1 dv) improvement in visibility. Additional upgrades would require major redesign and construction at a location where physical space is already constrained. Capital costs would be comparable to installing a new SCR and would achieve only marginal additional reductions in NO_X emissions. Because Unit MK2 has an existing SCR system designed to meet other air program requirements that could be operated year-round at reasonable cost, full-time operation of the existing SCR is considered to be BART for NO_X control on this unit.

EPA has provided presumptive BART emission rates that are broadly applicable to power plants larger than 750 MW but are not necessarily representative of smaller EGUs like Unit MK2. In the case of Unit MK2, the cyclone boiler has a relatively high uncontrolled NO_X emission rate ($\geq$2.0 lb/MMBtu); so it follows that the controlled emission rate, even at 90 percent control efficiency, would be above the presumptive norm of 0.10 lb/MMBtu applicable to larger EGUs of its type. The past decade of emissions records for Unit MK2 shows monthly average NO_X emission rates normally ranging between 50 and 100 percent of the RACT limit. The existing NO_X RACT limit of 15.4 ton/day, equivalent to of 0.37 lb/MMBtu*, corresponds to a NO_X control rate of approximately 85 percent.

PSNH has described operational and infrastructural changes that would be needed in order to allow the company to guarantee a NO_X performance level lower than the current effective limit of 0.37 lb/MMBtu (see Supporting Documentation, attached). This could be accomplished by increasing the frequency of maintenance cleanings and accelerating the rate of catalyst replacement to ensure a high level of NOx reduction capability at all times. The four major cost components would be:

1. The direct costs of extra inspections and maintenance cleanings for the air heater and SCR system,
2. The cost of purchased replacement power covering the periods of additional scheduled maintenance outages,
3. The cost of extra catalyst (early catalyst replacement), and
4. The increased cost of purchased replacement power associated with reduced flexibility to operate at partial load.

Calculations performed by PSNH assume a NOx emission rate of 0.8 lb/MMBtu during partial load operation. This relatively high emission rate means that, the lower the emission limit is set, the smaller must be the total time of partial load operation as a percentage of total operating time. As the emission limit is set lower, outage time would necessarily have to increase to prevent excessive emissions (that would otherwise occur under partial load operation). Replacement power at such times would represent an unavoidable cost.

Taking into account all of the described cost factors, PSNH has estimated that a reduction in the NO_X emission limit to 0.30 lb/MMBtu (an effective reduction of 0.07 lb/MMBtu) would have an incremental cost of approximately $800 per ton of NO_X removed and would result in a *potential* incremental emission reduction of about 1,000 tons per year. The indicated cost per ton falls within the generally regarded cost-effective range. At the same time, PSNH has estimated that further reduction of the NOx emission limit to 0.25-0.30 lb/MMBtu would yield diminishing returns, with the incremental cost per ton approximately one order of magnitude higher. NHDES concurs that such additional costs are not justifiable given the fact of negligible visibility benefit. When the historical performance of Unit MK2 is considered alongside the operational factors and estimated costs to achieve a higher performance level, NHDES finds that a NO_X emission rate of 0.30 lb/MMBtu reasonably represents the sustainable performance capabilities of this unit and is also appropriate as a BART control level for NO_X on a 30-day rolling average basis.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates two ESPs in series on Unit MK2. Mechanical collectors (cyclones) are effective only for coarse particle removal and would be impractical as a retrofit for Unit MK2, where the more efficient ESPs already exist. Fabric filters have performance levels

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* The 0.37 lb/MMBtu NO_X emission rate for MK2 is calculated from its maximum heat input rate of 3,473 MMBtu/hr and the applicable NO_X RACT limit of 15.4 tons per day, as follows:
$[(15.4 \text{ tons/day} \times 1 \text{ day/24 hr}) \times 2{,}000 \text{ lb/ton}] \div 3{,}473 \text{ MMBtu/hr} = 0.37 \text{ lb/MMBtu}$

comparable to ESPs and are a suitable PM control technology for power plant emissions. However, fabric filters are also impractical as a retrofit for Unit MK2 under present circumstances: ESPs already exist, physical space at the facility is limited, and the addition of an FGD system is now in progress.

The existing ESPs were previously upgraded to include state-of-the-art electronic controls. Further upgrading would require either major equipment substitutions or the addition of a third ESP in series with the two existing units. Adding a third ESP might be physically impossible because of the aforementioned spatial limitations following past improvements to emission control systems. To undertake either major equipment replacement or installation of a third ESP, if it could be done at all, would require a major capital expenditure. Typical equipment replacement costs for ESP upgrades may be in the range of $10,000 to $30,000 per MW. For Unit MK2, additional costs of this magnitude are not easily justified when weighed against the visibility improvement (less than 0.1 dv on the 20 percent worst visibility days) that would be realized.

The current PM emission limit for Unit MK2 is not reflective of the performance capabilities of the existing ESPs. However, the volume of available stack test data is insufficient to establish a conclusive, long-term BART performance level of 0.04 lb/MMBtu or lower for this unit. New Hampshire has adopted a new administrative rule that will hold TSP emissions to a maximum of 0.08 lb/MMBtu but will apply this limitation more broadly than BART requires. The new PM emission limit will affect both of Merrimack Station's coal-fired utility boilers – Unit MK1 (not a BART-eligible facility) and Unit MK2 – as explained below.

In the new rule, Units MK1 and MK2 are placed within a regulatory "bubble" for the purposes of TSP compliance. This arrangement serves both necessity and convenience because the two units will share a common stack. The following procedure was used to calculate the maximum allowable emission rate for the combined source:

1. For BART-eligible Unit MK2, the maximum heat input rating of 3,473 MMBtu/hr was multiplied by MANE-VU's lowest presumptive control level for TSP emissions, 0.02 lb/MMBtu, to obtain an emission rate of 69.46 lb/hr.

2. For non-BART Unit MK1, the maximum heat input rating of 1,238 MMBtu/hr was multiplied by the unit's permitted TSP limit, 0.27 lb/MMBtu, to determine an emission rate of 334.26 lb/hr.

3. The individual emission rates were summed to yield a total maximum emission rate of 403.72 lb/hr. This value was divided by the total maximum heat input rate, 4,711 MMBtu/hr, to obtain the new TSP emission limitation of 0.08 lb/MMBtu (rounded down from 0.086 lb/MMBtu).

By including Unit MK1 in the rule, the allowable TSP emissions from the two coal-fired units combined will be less than the allowable emissions would be if the limit for Unit MK1 remained separate and unchanged, and the limit for Unit MK2 were reduced to 0.04 lb/MMBtu, its approximate performance capability from actual stack test data.[†]

[†] For the bubble concept, the combined emission rate = 0.08 lb/MMBtu × 4,711MMBtu/hr = 377 lb/hr. For the stand-alone alternative, the sum of the individual emission rates = (0.04 lb/MMBtu × 3,473 MMBtu/hr) + (0.27 lb/MMBtu × 1,238 MMBtu/hr) = 473 lb/hr.

It is concluded that the existing ESPs, operating in conjunction with the FGD process, will provide the most cost-effective controls for particulate emissions. Continued operation of the existing ESPs, controlled to emission rates not exceeding the new emission limit described above, represents BART for PM control on Unit MK2.

6.3 Selecting a Pollution Control Plan for SO_2

PSNH Merrimack Station is installing a flue gas desulfurization system to remove mercury emissions in compliance with New Hampshire law. As a co-benefit, the FGD system is expected to remove more than 90 percent of SO_2 emissions. Because this installation is already mandated and because it will attain SO_2 removal rates approaching the BART presumptive norm of 95 percent (generally applicable to facilities larger than Merrimack Station), the FGD system is considered to be BART for SO_2 control on Unit MK2. (Note that, at an installed cost exceeding $1,000/kW, the FGD system being added to this facility is more expensive than the industry average and might not be viewed as cost-effective if its only purpose were to satisfy BART requirements.)

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Merrimack Station Unit MK2 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to meet or exceed BART requirements as well as changes in progress that are consistent with BART requirements. NHDES has already issued a temporary permit (construction permit) for the installation of the flue gas desulfurization system and is not requiring additional control technology for Merrimack Station at this time in order to comply with BART.

Table 7-1. Summary of BART Determinations for Unit MK2

Pollutant	Current Emission Controls	Additional Emission Controls in Progress	BART Controls	BART Emission Limit
NO_X	SCR	None	SCR	0.30 lb/MMBtu, 30-day rolling average
PM	Two ESPs in series	None	Two ESPs in series	0.08 lb/MMBtu total suspended particulate (TSP)
SO_2	Fuel sulfur limits set at 2.0 lb sulfur/MMBtu (averaged over 3 mos.) and 2.8 lb sulfur/MMBtu at any time	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis	Flue gas desulfurization (FGD), with required SO_2 percent reduction set at maximum sustainable rate, but not less than 90% on a calendar monthly average basis; existing fuel sulfur limits to remain in effect	10% of uncontrolled SO_2 emissions, calendar monthly average

NEW HAMPSHIRE BART ANALYSIS: Merrimack Station Unit MK2 (320 MW)

Pollutant	Emission Control Technology	Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[7]						
							Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref.
NO_X	SCR (existing)	85%	19,140 [1]	2,871 [2]	16,269		37,710,186	118	1,910,432	5,069,414	312	8
	SNCR	45%	19,140 [1]	10,527	8,613		3,876,771	12	4,781,136	5,105,893	593	8
PM	2 ESPs (existing)	99+%	30,060 [2]	210 [2]	29,850	min.	23,280,363	73	1,086,417	2,571,006	86	9
						max.	62,080,967	194	1,940,030	7,140,553	239	
	Fabric Filters	99%	30,060 [2]	301	29,759	min.	18,624,290	58	2,172,834	3,732,991	125	9
						max.	62,080,967	194	3,104,048	8,304,571	279	
SO_2	Lower-S coal (existing)	40% [3]	—	—	—		—	—	—	—	—	
	FGD	90% [4]	20,902 [5]	2,090	18,812 [6]		457,000,000	1,055	unknown	unknown	unknown	10

1 Estimated.

2 2002 (baseline) emissions as taken from NHDES data summary derived from facility's annual emissions statement.

3 Estimated average reduction in fuel sulfur content with use of lower-S coal, resulting in equivalent reduction in SO_2 emissions.

4 Additional control level on emissions after existing controls have been applied; overall control level with use of lower-S coal is estimated to be 40 + 90(1 - 0.40) = 94%

5 2002 (baseline) emissions with use of lower-sulfur coal at ~1.0 % S by weight.

6 Reductions from baseline emissions.

7 All cost estimates adjusted to 2008$.

8 USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

9 NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

10 FGD capital cost is PSNH's estimate (2008$) for Units MK1 (113 MW) and MK2 (320 MW) combined.

Merrimack Station Unit MK2: NO_X Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Generation capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	111.48	103.46	33,108,152	2,773,470	0.74	0.69	219,771	0.67	0.65	1,457,518	1,677,289	4,450,759	16,269	274
SNCR	11.04	10.64	3,403,662	285,125	0.16	0.15	49,328	1.46	1.85	4,148,332	4,197,661	4,482,786	8,613	520

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M	Scaled Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
SCR	126.98	117.84	37,710,186	3,158,982	0.84	0.78	250,319	0.76	0.74	1,660,113	1,910,432	5,069,414	16,269	312
SNCR	12.57	12.11	3,876,771	324,757	0.18	0.18	56,185	1.66	2.11	4,724,951	4,781,136	5,105,893	8,613	593

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Merrimack Station Unit MK2: PM Controls

Plant type	wet-bottom, cyclone, coal-fired boiler	
Capacity	320	MW
Maximum heat Input	3,473	MMBtu/hr
Capacity factor	80	%
Annual hours	8,760	hr/yr
Annual production	2,242,560,000	kWh/yr
Flue gas flow rate	1,362,620	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	7,180	6,703	7,462	7,280	7,577	7,477	6,519
Total Heat Input*	22,013,513	22,006,524	24,024,382	23,795,575	25,328,218	25,448,437	18,282,000
Capacity factor**	72.4%	72.3%	79.0%	78.2%	83.3%	83.6%	60.1%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	20,439,300	1,712,200	0.25	0.45	953,834	2,666,034	29,850	89
	max.	40.00	54,504,800	4,565,867	0.65	0.60	1,703,275	6,269,142	29,850	210
Wet ESP	min.	15.00	20,439,300	1,712,200	0.15	0.25	545,048	2,257,248	29,850	76
	max.	40.00	54,504,800	4,565,867	0.50	0.50	1,362,620	5,928,487	29,850	199
Fabric Filter - Reverse Air	min.	17.00	23,164,540	1,940,494	0.35	0.70	1,430,751	3,371,245	29,759	113
	max.	40.00	54,504,800	4,565,867	0.75	0.80	2,112,061	6,677,928	29,759	224
Fabric Filter - Pulse Jet	min.	12.00	16,351,440	1,369,760	0.50	0.90	1,907,668	3,277,428	29,759	110
	max.	40.00	54,504,800	4,565,867	0.90	1.10	2,725,240	7,291,107	29,759	245

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	23,280,363	1,950,196	0.28	0.51	1,086,417	3,036,613	29,850	102
	max.	45.56	62,080,967	5,200,523	0.74	0.68	1,940,030	7,140,553	29,850	239
Wet ESP	min.	17.09	23,280,363	1,950,196	0.17	0.28	620,810	2,571,006	29,850	86
	max.	45.56	62,080,967	5,200,523	0.57	0.57	1,552,024	6,752,547	29,850	226
Fabric Filter - Reverse Air	min.	19.36	26,384,411	2,210,222	0.40	0.80	1,629,625	3,839,848	29,759	129
	max.	45.56	62,080,967	5,200,523	0.85	0.91	2,405,637	7,606,160	29,759	256
Fabric Filter - Pulse Jet	min.	13.67	18,624,290	1,560,157	0.57	1.03	2,172,834	3,732,991	29,759	125
	max.	45.56	62,080,967	5,200,523	1.03	1.25	3,104,048	8,304,571	29,759	279

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BART Analysis for PSNH Newington Station Unit NT1

January 14, 2011

Amended August 26, 2011

BART Analysis for PSNH Newington Station Unit NT1

1. INTRODUCTION

Unit NT1 is the sole electrical generating unit at PSNH Newington Station. It operates at irregular times, principally during periods of peak electric demand. Power is derived from an oil- and/or natural-gas-fired steam-generating boiler with a heat input rating of 4,350 MMBtu/hr and an electrical output of 400 MW. Installed in 1968, the boiler is equipped with low-NOx burners, an overfire air system, and water injection to minimize the formation of oxides of nitrogen (NO_X) during the combustion process. The facility also has an electrostatic precipitator (ESP) to capture particulate matter (PM) in the flue gases. Partial control of SO_2 emissions is provided by sulfur content limits on the fuel oil.

2. CURRENTLY AVAILABLE RETROFIT TECHNOLOGIES, POTENTIAL COSTS, AND OTHER ENVIRONMENTAL AND ENERGY IMPACTS

2.1 Retrofit Technologies for NO_X Control

NO_X emission control technology options available and potentially applicable to Unit NT1 are combustion controls, selective non-catalytic reduction, and selective catalytic reduction.

Combustion Controls

Controls on the combustion process can reduce NO_X formation by as much 75 percent. Combustion controls or firing practices include such measures as staged combustion, limiting excess air, providing overfire air, recirculating the flue gases, using low-NO_X burners, and injecting water or steam.

Operating with low excess air involves restricting the amount of combustion air to the lowest possible level while maintaining efficient and environmentally compatible boiler operation. Because less oxygen is introduced into the combustion zone, NO_X formation is inhibited. Adjustments to the air supply may affect normal boiler operation and may reduce operational flexibility. The effectiveness of limiting excess air varies from boiler to boiler, but typical NO_X reductions are 10 to 25 percent from uncontrolled levels.

Overfire air (OFA) is a method where some of the total combustion air is diverted from the burners and injected through ports above the top burner level. This staged combustion reduces fuel-based NO_X formation in the oxygen-deficient primary combustion zone and limits thermal NO_X formation because of the lower peak flame temperature (i.e., combustion occurs over a larger portion of the furnace). For oil-fired boilers, OFA typically reduces NO_X emissions by 15 to 45 percent.

Flue gas recirculation (FGR) involves reinjecting a portion of the cooled flue gas into the combustion chamber. FGR dilutes the oxygen concentration in the combustion zone and depresses peak flame temperature by adding a large amount of cooled gas to the fuel-air mixture, resulting in less thermal NO_X formation. FGR reduces NO_X emissions by about 40 to 60 percent in oil-fired boilers.

Low-NO_X burners (LNB) are designed to control fuel/air mixing and increase heat dissipation. These alternative burners can be installed on new boilers or retrofitted on older units. LNB technology integrates staged combustion in the burner. A typical LNB creates a fuel-rich primary combustion zone, thus lowering the formation of fuel-based NO_X. At the same time, limited combustion air reduces the flame temperature, minimizing the formation of thermal NO_X. Combustion is completed in a lower-temperature, fuel-lean zone. LNB retrofits have been shown to reduce NO_X formation by 30 to 55 percent.

Water or steam can be injected into the boiler combustion zone to reduce the peak flame temperature, with a corresponding reduction in thermal NO_X formation. Water/steam injection can reduce NO_X emissions by as much as 75 percent in gas-fired boilers and slightly less in oil-fired boilers.

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion technology that involves injecting ammonia or urea into specific temperature zones in the upper furnace or convective pass. The ammonia or urea reacts with NO_X in the flue gas to produce nitrogen and water. The effectiveness of SNCR depends on the temperature where reagents are injected, the mixing of the reagent in the flue gas, the residence time of the reagent within the required temperature window, the ratio of reagent to NO_X, and the sulfur concentration in the flue gas. (Sulfur in the flue gas, originating from the sulfur content of the fuel, can combine with ammonia to form solid sulfur compounds such as ammonium bisulfate that may become deposited in downstream equipment.) There is limited commercial experience with SNCR from which to judge its effectiveness for oil-fired boilers. NO_X reductions of 35 to 60 percent have been achieved through the use of SNCR on some oil-fired boilers operating in the United States.

Selective Catalytic Reduction (SCR)

SCR is another post-combustion technology that involves injecting ammonia into the flue gas in the presence of a catalyst to reduce NO_X to nitrogen and water. The SCR reactor can be located at various positions in the process, including upstream of an air heater and particulate control device, or downstream of an air heater, particulate control device, and flue gas desulfurization system. The performance of SCR is influenced by flue gas temperature, fuel sulfur content, ammonia-to-NO_X ratio, inlet NO_X concentration, space velocity, catalyst design, and catalyst condition. NO_X emission reductions of about 75 to 90 percent have been obtained with SCR on coal-fired boilers operating in the U.S. Although there is little experience with SCR systems on oil-fired boilers, SCR retrofits for oil-fired EGUs using the latest technology would be expected to achieve NO_X control efficiencies toward the upper end of this range.

2.1.1 Potential Costs of NO_X Controls

The estimated costs of NO_X emission controls at Newington Station Unit NT1 are presented in Table 2-1. These estimates are based on assumptions used in EPA's Integrated Planning Model for the EPA Base Case 2006 (V.3.0), for retrofitting an electric generating unit

(EGU) the size of Unit NT1. For low-NO_X burners, the total annual cost is estimated to be about $830,000, or $1,470 per ton of NO_X removed. With the addition of overfire air, this cost rises to $1,130,000, or $1,600 per ton. For SNCR, the total annual cost is estimated to be $730,000, or $1,030 per ton. For SCR, the total annual cost doubles to $1,410,000; but the unit cost is only moderately higher at $1,180 per ton of NO_X removed. Because Unit NT1 is primarily a peak-load generator, these estimates are based on a 20-percent capacity factor.

Table 2-1. Estimated NO_X Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost ($)	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
LNB	21.9	7,900,000	170,000	830,000	1,470
LNB+OFA	29.8	10,700,000	230,000	1,130,000	1,600
SNCR	12.3	3,300,000	450,000	730,000	1,030
SCR	36.7	11,500,000	440,000	1,410,000	1,180

Estimates are derived from USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006. Costs are scaled for boiler size. All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and 701million kWh annual generation. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on the following estimates of NO_X removed: 563 tons for LNB; 704 tons for LNB+OFA; 704 tons for SNCR; and 1,196 tons for SCR.

Low-NO_X burners have previously been reported to operate in a cost range of $200 to $500 per ton of NO_X removed (NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005); however, this cost range is likely to be more relevant to larger plants operating at higher capacity factors than Newington Station.

2.1.2 Other Environmental and Energy Impacts of NO_X Controls

SNCR and SCR both use urea or anhydrous ammonia. Ammonia is a regulated toxic air pollutant in New Hampshire. Facilities using these technologies must limit their ammonia emissions, which may be released either in their flue gases or as fugitive emissions from the handling and storage of urea or anhydrous ammonia. A facility must also maintain a risk management plan if the quantities of stored ammonia exceed the applicable regulatory threshold.

Ammonia from SNCR that becomes entrained in the fly ash may affect the resale value or disposal cost of the ash. Ammonia in the flue gas may produce a more visible plume, depending on the ammonia concentration in the gas stream. High ammonia concentrations in the boiler from SNCR can react with sulfate to form ammonium bisulfate, which deposits on the economizer, air heater, and other surfaces. Ammonium bisulfate can also plug filter bags in a baghouse. SNCR may generate nitrous oxide emissions, a greenhouse gas.

With SCR, the formation of ammonium bisulfate may be exacerbated by the ability of this catalyst-based technology to oxidize SO_2 to SO_3, resulting in higher sulfate concentrations than would otherwise exist. Ammonium bisulfate formation can be reduced by controlling excess ammonia and using catalysts that minimize SO_2 oxidation. The air heater and other surfaces where the ammonia bisulfate may deposit must be acid washed periodically. Acid washing helps to maintain the efficiency of the air heater and prevents plugging to allow the free flow of flue gases through it. An SCR may also require a fan upgrade to overcome extra pressure drop across the catalyst. The increase in fan capacity consumes a small amount of energy.

NO_X emission reductions provide environmental and public health benefits beyond visibility improvement – most notably, reductions in acid rain and ground-level ozone. NO_X is a chemical precursor to ozone formation and is one of the primary compounds contributing directly to acid rain formation. A decrease in acid rain production improves water quality and the health of ecosystems sensitive to low pH.

2.2 Retrofit Technologies for PM Control

PM control technologies available and potentially applicable to Unit NT1 are electrostatic precipitators, fabric filters, mechanical collectors, and particle scrubbers.

Electrostatic Precipitators (ESPs)

Electrostatic precipitators capture particles through the use of electrodes, which are electrical conductors used to make contact with non-metallic parts of a circuit. An ESP consists of a small-diameter negatively charged electrode (usually a set of individual wires or a grid) and a grounded positively charged plate. In operation, a strong electric charge from the negatively charged electrode sets up a one-directional electric field. When particle-laden gases pass through this electric field, the particles become charged and are then drawn to the positive collecting surface (the plate), where they are neutralized. The particles are then collected by washing or knocking the plate, causing the particles to fall into a collection hopper. Existing electrostatic precipitators are typically 40 to 60 percent efficient. New or rebuilt ESPs can achieve collection efficiencies of more than 99 percent.

For older units, options for upgrading an ESP system include: replacement of existing control systems with modern electronic controllers; replacement of old-style wire and plate systems inside the ESP with new, rigid electrode systems; addition of new ESP fields; or addition of entire new units (in series). The feasibility of any particular upgrade will be influenced by spatial limitations or design constraints on a case-by-case basis.

Fabric Filters

Fabric filtration devices, or baghouses, incorporate multiple fabric filters/bags inside a containment structure. These devices work on the same principal as a vacuum cleaner bag. The particle removal efficiency of the fabric filter system depends on a variety of particle and operational parameters. The physical characteristics of particle size distribution, particle cohesion, and particle electrical resistivity are important variables. Operational parameters affecting collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, and cleaning intensity. The structure of the fabric filter, filter composition, and bag properties also affect collection efficiency. Collection efficiencies of baghouses may exceed 99 percent.

Mechanical Collectors and Particle Scrubbers

Mechanical collectors, such as cyclones, are most effective at collecting coarse particulate matter (i.e., particles with a diameter of 10 micrometers or larger). Finer particles escape cyclones along with the flue gases. For this reason, mechanical collectors are generally most useful when used in conjunction with other pollution control equipment. The typical collection efficiency of mechanical collectors is about 85 percent for larger particle sizes.

Scrubbing systems involve the injection of water and/or chemicals into the flue gas to wash unwanted pollutants from the gas stream through physical or chemical absorption/adsorption. Scrubbing systems have been shown to reduce PM_{10} emissions by 50 to 60 percent but are generally less effective for removal of fine particles.

Because mechanical collectors and particle scrubbers are more costly and less efficient than other control options (i.e., ESPs, baghouses), these lower-performing technologies are rarely used today for removing particulate matter from power plant emissions. Consequently, mechanical collectors and scrubbers are not considered further in this analysis for the control of PM emissions.

2.2.1 Potential Costs of PM Controls

Table 2-2 presents cost data for PM controls as developed from NESCAUM's *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. Approximate cost ranges are provided for two types of ESPs and two types of fabric filters applicable to a retrofit installation the size of Unit NT1. Capital and operating costs are based on flue gas flow rates in actual cubic feet per minute (acfm).

Table 2-2. PM Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
Dry ESP	73-194	29.3-78.1 million	1.4-2.4 million	3.8-9.0 million	27,000-63,000
Wet ESP	73-194	29.3-78.1 million	0.8-2.0 million	3.2-8.5 million	23,000-60,000
Fabric filter – reverse air	82-194	33.2-78.1 million	2.0-3.0 million	4.8-9.6 million	14,000-29,000
Fabric filter – pulse jet	58-194	23.4-78.1 million	2.7-3.9 million	4.7-10.4 million	14,000-31,000

Reference: NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005. (Note that these costs were developed for coal-fired boilers.) All costs are adjusted to 2008 dollars. Total annual cost is for retrofit of a 400-MW unit with 20% capacity factor and flue gas flow rate of 1.71 million acfm. Total annual cost includes amortization of capital cost over 15 years at 3.0% interest rate. Average cost per ton is based on 142 tons of PM removed for ESPs and 335 tons of PM removed for fabric filters.

The costs for ESPs and fabric filters are of similar magnitude, with total annual costs ranging from about $3.2 million to $10.4 million, or $14,000 to $63,000 per ton of PM removed. Because Unit NT1 already has an ESP installed and operating, the tabulated costs are useful for comparative purposes only. For facilities with existing ESPs, typical equipment replacement costs to upgrade performance may be in the range of $10,000 to $30,000 per MW. (M. Sankey and R. Mastropietro, "Electrostatic Upgrade Strategy: Get the Most From What You Have," Hamon Research-Cottrell, Inc., April, 1997.)

2.2.2 Other Environmental and Energy Impacts of PM Controls

PM controls collect particulate matter, or fly ash, suspended in the flue gases. In some cases, the fly ash is injected back into the boiler, an arrangement that improves boiler efficiency by recapturing the residual heating value of the fly ash. If the fly ash is not reinjected, it must be either landfilled or reclaimed, e.g., as a supplement in concrete production or as a component in other manufactured products.

2.3 Retrofit Technologies for SO_2 Control

SO_2 control technologies available and potentially applicable to Unit NT1 are scrubber systems for flue gas desulfurization, and use of low-sulfur coal.

Flue Gas Desulfurization

Scrubber systems use chemical reagents to "scrub" or "wash" unwanted pollutants from a gas stream. Flue gas desulfurization (FGD) processes based on this technology concept are classified as either wet or dry. Wet scrubbers are more commonly used at power plants to control acid gas emissions. Scrubbers of all types may be effective for the removal of particulate matter, mercury, sulfur dioxide, and other air pollutants.

In the wet FGD process, an alkaline reagent is applied in liquid or slurry form to absorb SO_2 in the flue gas. A PM control device is always located upstream of a wet scrubber. Lime/limestone scrubbers, sodium scrubbers, and dual alkali scrubbers are among the commercially proven wet FGD systems. Wet regenerative (meaning the reagent material can be treated and reused) FGD processes are an attractive option because they allow higher sulfur removal rates and produce minimal wastewater discharges.

For coal-fired power plants, the reagent is usually lime or limestone; and the reaction product is calcium sulfite or calcium sulfate. The solid compounds are collected and removed in downstream process equipment. Calcium sulfate (gypsum) sludge produced in FGDs can be recycled into saleable byproducts such as wallboard, concrete, and fertilizer. Sulfate products that are not recycled must be landfilled.

SO_2 removal efficiencies for existing wet limestone scrubbers range from 31 to 97 percent with an average of 78 percent (NESCAUM, "Assessment of Control Technology Options for BART-Eligible Sources," March 2005). For new FGD systems installed at large (>750 MW) coal-fired power plants, the presumptive norm is 95 percent reduction of SO_2 emissions (USEPA, Appendix Y to Part 51 – Guidelines for BART Determinations under the Regional Haze Rule). While experience with FGD systems on smaller, oil-fired EGUs is generally lacking, it is anticipated that such installations would perform at a similar level, achieving SO_2 removal efficiencies of 90 percent or greater.

Dry (or semi-dry) FGD processes are similar in concept to wet FGD processes but do not saturate the flue gas stream with moisture. Dry scrubbers are of two general types: dry sorbent injection and spray dryers. With the former, an alkaline reagent such as hydrated lime or soda ash is injected directly into the flue gas stream to neutralize the acid gases. In spray dryers, the flue gas stream is passed through an absorber tower in which the acid gases are absorbed by an atomized alkaline slurry. The SO_2 removal efficiencies range from 40 to 60 percent for existing dry injection systems and from 60 to 95 percent for existing lime spray dryer systems (NESCAUM, 2005). A PM control device (ESP or fabric filter) is always installed downstream of a dry or semi-dry scrubber to remove the sorbent from the flue gas.

Low-Sulfur Fuels

Because SO_2 emissions are directly related to the sulfur content of the fuel burned, reducing the amount of sulfur in the fuel reduces SO_2 emissions. For facilities that burn fuel oil, switching to a lower-sulfur fuel may be a cost-effective control option. Switching from high-sulfur residual fuel oil to low-sulfur residual fuel oil or low-sulfur distillate fuel oil is one possible control strategy. For facilities that have the option to replace fuel oil with natural gas or can co-fire with natural gas, increasing the use of natural gas is another effective control strategy. Sulfur dioxide emissions from burning natural gas are negligible in comparison to those from burning fuel oil. When substituting natural gas for fuel oil, the resulting SO_2 emission reductions are roughly proportional to the fraction of natural gas burned on a Btu-equivalent basis.

2.3.1 Potential Costs of SO_2 Controls

There is little or no experience with, or cost data on, flue gas desulfurization at oil-fired power plants. However, the technology is similar to FGD for coal-fired plants. Therefore, the costs of an FGD system for PSNH Newington Station may be crudely approximated by extrapolating from the costs of FGD for PSNH Merrimack Station.

The flue gas desulfurization system at Merrimack Station is being installed to reduce mercury emissions (with SO_2 removal as a co-benefit) at its two coal-fired boilers. These units have a combined generating capacity of 433 MW, or slightly greater than the capacity of Newington Station Unit NT1. The company's capital cost estimate for the wet limestone FGD system is $457 million, or $1,055/kW (both amounts in 2008$), which is said to be in line with project costs for multiple-unit scrubber installations occurring elsewhere in the United States. However, PSNH's estimated cost per kilowatt is at least triple the cost range for FGD systems as reported in MACTEC Federal Programs, Inc., "Assessment of Reasonable Progress for Regional Haze in MANE-VU Class I Areas," Final, July 9, 2007 (see Reasonable Progress Report, Attachment Y). The PSNH estimated cost is also more than double the estimate of $300/kW to $500/kW as reported in a 2008 survey of FGD systems (George W. Sharp, "What's That Scrubber Going to Cost?," *Power*, March 1, 2009). The higher cost-per-kW for Unit MK2 may reflect industry-wide increases in raw material, manufacturing, and construction costs but may also reflect site-specific factors such as unit size, type, and difficulty of retrofit.

Using the latest Merrimack Station estimate of $1,055/kW for scaling purposes, the total capital cost of a wet limestone FGD system for Newington Station Unit NT1 would be roughly $422,000,000. Much caution is necessary in relating this number to the Newington facility: Note that the cost of FGD on oil-fired boilers previously has been estimated to be about *twice* the cost of FGD on coal-fired boilers of comparable size (NESCAUM, 2005).

The costs of switching to a low-sulfur fuel oil at Unit NT1 would depend on the incremental costs of purchasing the lower-sulfur product at prevailing market prices. The long-term price differential between 1.0%-sulfur (low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about 7.5 cents/gallon. The differential between 0.5%-sulfur (ultra-low-S) residual fuel oil and 2.0%-sulfur residual fuel oil is estimated to be about twice this amount, or 15 cents/gallon (both estimates in 2008$ based on Energy Information Agency compiled price data for the period 1983-2008.) Using these unit prices, the total cost of switching to low-S residual fuel oil is approximately $3.3 million per year, or $1,900 per ton of SO_2 emissions removed; and the cost of switching to ultra-low-S residual fuel oil is approximately $6.6 million per year, or also $1,900 per ton of SO_2 emissions removed (both estimates based on 2002 actual fuel oil usage; note that fuel oil usage in 2006-2009 has been below 2002 levels). These results imply that the costs of switching fuel oils may be relatively constant on a $/ton basis as long as supplies are adequate.

Table 2-3 summarizes the approximate costs of flue gas desulfurization and fuel switching as SO_2 control options for PSNH Newington Station Unit NT1. The costs for switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil are listed. At any given time, the actual cost of fuel switching would vary in proportion to the applicable fuel price differential.

Table 2-3. SO_2 Control Costs

Control Technology	Capital Cost ($/kW)	Capital Cost $	O&M Cost ($/yr)	Total Annual Cost ($/yr)	Average Cost ($/ton)
FGD	1,055	422,000,000	unknown	unknown	unknown
Switch to 1.0%-S oil	—	—	3,300,000	3,300,000	$1,900
Switch to 0.5%-S oil	—	—	6,600,000	6,600,000	$1,900
Capital cost estimate for FGD is based on reported cost per kilowatt-hour for FGD system at PSNH Merrimack Station. Actual costs for Newington Station could be much higher. O&M costs for fuel switching are based on 2002 annual fuel usage of 44,140,000 gallons and estimated fuel price differential of 7.5 or 15 ¢/gallon for substitution of 1.0%-S or 0.5%-S residual fuel oil, respectively.					

In a similar analysis performed independently by PSNH (see attached letter), the company has estimated the costs of fuel switching based on historical fuel prices for the period 2002-2009 as compiled by Platts[‡]. Table 2-4 reproduces the fuel oil prices used by PSNH:

Table 2-4. Historical Fuel Oil Prices, 2002-2009 ($/barrel)

Year	2%S Oil	1%S Oil	0.7%S Oil	0.5%S Oil	0.3%S Oil
2002	21.20	22.45	23.26	23.80	25.25
2003	24.95	27.48	29.26	30.45	32.63
2004	25.25	27.92	30.04	31.46	34.53
2005	37.00	41.00	44.00	46.00	50.10
2006	45.50	46.30	48.46	49.90	54.12
2007	53.70	53.45	56.54	58.60	62.86
2008	75.25	77.80	81.10	83.30	92.16
2009	49.90	50.75	51.98	52.80	55.83
Source: Platts. 2009 data include costs through 9/09.					

[‡] Platts, a division of The McGraw-Hill Companies, is a provider of energy information services.

Using this historical fuel price record and PSNH's calculated SO_2 emission reductions from fuel switching, the New Hampshire Department of Environmental Services (NHDES) has prepared alternate estimates of the increased costs of fuel switching from 2.0%-S residual fuel oil to 1.0%-S or 0.5%-S residual fuel oil, and other variations, in Table 2-5. Costs are listed in terms of \$/barrel, \$/hour, and \$/ton. This analysis produces somewhat less conservative (lower) estimates of the cost of fuel switching than the \$1,900/ton estimate given above. In either analysis, the cost-effectiveness of switching to 0.5%-sulfur residual fuel oil appears reasonable as long as supplies remain stable. Switching to 0.3%-sulfur fuel oil could also prove reasonable in the future if prices were to stay within their recent historical range and future supplies could be assured.

Table 2-5. Costs of Fuel Switching Based on Historical Fuel Oil Prices

Fuel Switch	SO_2 Emission Reduction* (lb/hr)	Increased Cost (\$/barrel)		Increased Cost (\$/hour)**		\$/ton of SO_2 Removed***	
		low	high	low	high	low	high
→ 2% to 1%	***5,228.7***	***0***	***4***	***0***	***2,692***	***0***	***1,030***
1% to 0.7%	1,470.3	1	3.3	673	2,222	414	3,022
0.7% to 0.5%	957.0	1	2.2	673	1,482	586	3,095
0.5% to 0.3%	935.3	3	9	2,020	6,059	2,967	12,957
2% to 0.7%	6,699.0	2	7	1,34	4,712	402	1,407
→ 2% to 0.5%	***7,656.0***	***3***	***9***	***2,019***	***6,058***	***528***	***1,583***
2% to 0.3%	8,591.3	4	17	2,692	11,444	627	2,664

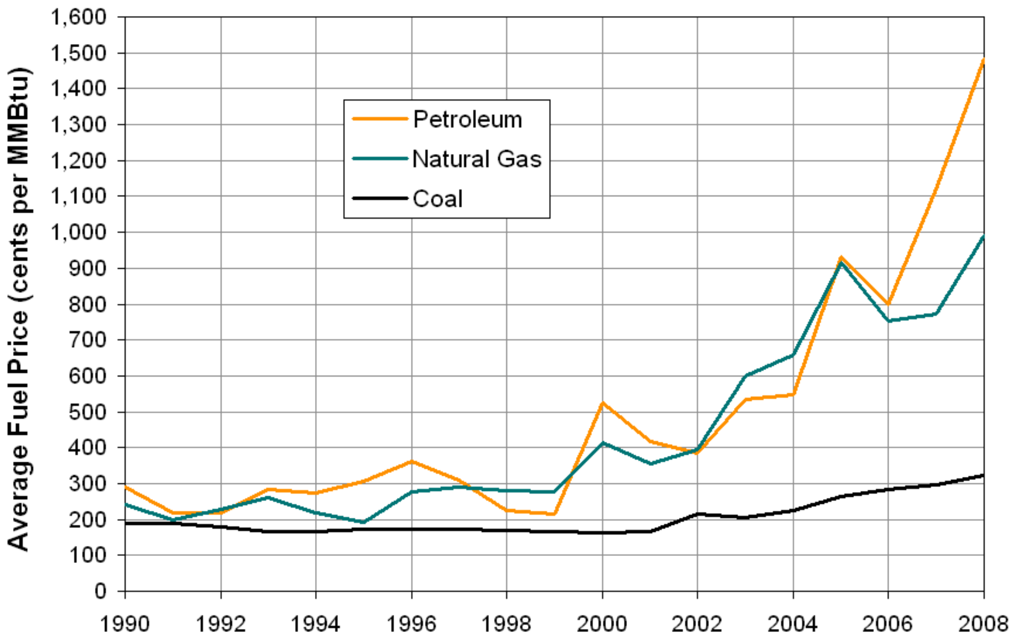
* Calculated reduction, from PSNH letter dated December 4, 2009.
** \$/barrel ÷ 42 gal/barrel ÷ 0.153846 MMBtu/gal × MMBtu/hr = \$/hr
*** \$/hr ÷ lb/hr × 2000 lb/ton = \$/ton

Besides switching residual fuel oils to reduce SO_2 emissions, other proposed options include replacing 2.0%-S residual fuel oil with low-sulfur distillate fuel oil or natural gas. Although distillate fuel oil is sometimes used during startup of Unit NT1, the boiler is not designed to operate routinely on this fuel; and retrofitting the boiler for this purpose would involve major capital expenditure. Burner replacements to combust distillate fuel oil could exceed \$20 to \$30 million (approximately \$1 to 2 million per burner) in direct capital costs, not including the additional costs of engineering and any required auxiliary equipment.

The cost determinations associated with using natural gas are more complicated. Unit NT1 can be fired with either natural gas or liquid fuel (i.e., residual fuel oil or biofuel), or it can be co-fired with both types of fuel at the same time. However, because of physical limitations to the boiler's design, the unit cannot operate at full capacity when fueled solely by natural gas. In order to reach maximum heat input, the boiler must either use liquid fuel or be co-fired with both fuel types. (Unit NT1 can operate at up to about 50 percent of maximum heat input from natural gas, with no corresponding limitation on liquid fuel.) Firing Unit NT1 entirely with natural gas might be technically feasible but would require more than just burner replacements: it would require modifications to other major boiler components or replacement of the entire boiler. Such measures cannot be economically justified. However, using natural gas – to the extent that Unit NT1 can burn this fuel with existing equipment – remains a viable option as long as the cost of this fuel is competitive with the cost of residual fuel oil and biofuel.

Volatile energy commodity prices in recent years and the uncertainty of future fuel prices make it difficult to provide a useful estimate of the cost of substituting natural gas for residual fuel oil. As seen in Figure 2-1, past prices of natural gas and petroleum fuels, on a BTU-equivalent basis, exhibit similar trends; but the price differentials show wide variation from year to year. Consequently, no cost estimate for this fuel switching option is presented.

Figure 2-1. Comparison of Fossil Fuel Prices for Electric Generation in New England (1990-2008)



Data source: Energy Information Administration, Form EIA-923, "Power Plant Operations Report."
http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html

2.3.2 Other Environmental and Energy Impacts of SO_2 Controls

An FGD system typically operates with high pressure drops across the control equipment, requiring increased energy usage for blowers and circulation pumps. Some configurations of FGD systems also require flue gas reheating to prevent operational problems (including physical damage to equipment), resulting in higher fuel usage per unit of net electrical generation. Documentation for EPA's Integrated Planning Model (IPM®) indicates that a wet FGD system reduces the generating capacity of the unit by about 2 percent.

Flue gas desulfurization has impacts on the operation of solid waste and wastewater management systems. In addition to removing SO_2, the FGD process removes mercury and other metals and solids. Often, gypsum produced in a limestone FGD process is recycled or sold to cement manufacturers; otherwise, the sludge must be stabilized and placed in an approved landfill. Gypsum must be dewatered before it can be handled, resulting in a wastewater stream that requires treatment. This wastewater stream increases the sulfates, metals, and solids loadings on the receiving wastewater treatment plant. Sometimes an additional clarifier is required to remove wastewater solids coming from the FGD system.

Wet FGDs increase the amount of water vapor entrained in the flue gas. The result is a lower stack exit temperature and a more visible plume at the stack outlet.

Switching to lower-sulfur fuel oil generally reduces boiler maintenance requirements because less particulate matter is emitted. With fewer material deposits occurring on internal boiler surfaces, the intervals between cleanings/outages can be longer. Also, because lower-sulfur oil reduces the formation of sulfuric acid emissions, corrosion is reduced and equipment life is extended.

3. DISCUSSION OF CURRENT POLLUTION CONTROL EQUIPMENT AND EMISSIONS

3.1 Discussion of Current NO_X Emissions and Controls

PSNH Newington Station Unit NT1 currently operates with low-NOx burners, an overfire air system, and water injection to minimize NO_X formation. For compliance with NO_X RACT requirements, the facility's existing air permit limits NO_X emissions from this unit to a daily average of 0.35 lb/MMBtu when burning oil and 0.25 lb/MMBtu when burning a combination of oil and gas. NHDES reviewed emissions data for Unit NT1 for the period from 2003 to 2005, when more than 99 percent of the gross heat input came from residual fuel oil. Monthly average NO_X emissions ranged between 0.21 and 0.30 lb/MMBtu. These values compare favorably with the facility's NO_X RACT limits. Actual NO_X emissions from this unit were 943 tons in 2002.

3.2 Discussion of Current PM Emissions and Controls

Unit NT1 has an electrostatic precipitator to capture PM emissions. In an EPA inspection report on this unit from December 15, 1989, a table of design values for the ESP listed a particulate removal efficiency of 93 percent. It is unknown whether the stated efficiency is representative of actual long-term performance. The facility's air permit (TV-OP-054, March 9, 2007; administrative amendment, December 17, 2007) sets an emission limit of 0.22 lb/MMBtu total suspended particulate matter (filterable TSP). The single available stack test on Unit NT1 measured a controlled TSP emission rate of 0.058 lb/MMBtu, which is well below the permit limit. The tested emission rate lies within the expected range for a properly operating ESP at a plant like Newington and may serve as a better measure of performance than any stated efficiency for this control device. Actual TSP emissions from Unit NT1 were 198 tons in 2002.

3.3 Discussion of Current SO_2 Emissions and Controls

Sulfur dioxide emissions are partially controlled at PSNH Newington Station by existing limits on fuel oil sulfur content. Permitted fuel sulfur limits are 2.0% sulfur by weight for No. 6 fuel oil and 0.4% sulfur by weight for No. 2 fuel oil. Unit NT1 does not have an individual limitation on sulfur dioxide emissions but is subject to an annual cap of 55,150 tons of SO_2 for all electrical generating units at PSNH's Merrimack, Newington, and Schiller Stations combined. Actual SO_2 emissions from Unit NT1 were 5,226 tons in 2002. The average sulfur content of No. 6 fuel oil burned that year was 1.2% by weight, which is typical of values from the most recent decade. In 2009, the average was 1.0%.

4. REMAINING USEFUL LIFE OF UNIT

Where a reasonable control option is available for a BART-eligible unit, the unit should be controlled in a manner consistent with BART and the expected useful life of the unit. Originally, electric generating units were estimated to have a life expectancy of 30 to 40 years, but many units are lasting 50 years or more. In many cases, it is less expensive to keep existing units operating than to build replacement facilities and/or new transmission lines. Newington Station Unit NT1 was built in 1969. However, because this facility runs primarily on fuel oil, its remaining useful life may depend more on future commodity supplies/prices and other external factors than on the longevity of plant equipment.

5. DEGREE OF VISIBILITY IMPROVEMENT ANTICIPATED FROM BART

5.1 CALPUFF Modeling Analysis

NHDES performed a set of CALPUFF model runs for the New Hampshire BART-eligible sources under controlled and uncontrolled conditions. The same methodologies used for the CALPUFF modeling work for Merrimack Station Unit MK2 were applied to the modeling for Newington Station Unit NT1.

In previous modeling, MANE-VU used CALPUFF to assist in the identification of BART-eligible sources. This modeling assumed natural visibility conditions (about 7 dv) to produce the most conservative results possible, thereby minimizing the number of sources that would "model out" of BART requirements. Under these conditions, uncontrolled emissions from Unit NT1 produce theoretical CALPUFF worst-case impacts of 1.22 dv at Acadia National Park. EPA considers it acceptable to exempt sources when this form of conservative modeling indicates that a source produces less than 0.5 dv of impact. MANE-VU considers an exemption level of 0.2 to 0.3 dv to be more appropriate but prefers, and has applied, an even more conservative exemption level of 0.1 dv. CALPUFF modeling results for baseline emissions from Unit NT1 exceed all of these exemption levels. The CALPUFF-predicted visibility benefits from BART controls on 20% worst natural and 20% worst baseline visibility days are presented in Table 5-1.

As seen in the table, more benefit would result generally from SO_2 emission reductions than NOx emission reductions. This finding reinforces MANE-VU's early determination that SO_2 was the primary target pollutant for maximizing visibility improvements. NO_X, while also an important visibility impairing pollutant, reacts with ammonia less preferentially than does SO_2 and is also less hydrophilic than SO_2. As a result, NO_X has a lower rate of formation of haze-causing particles and impairs visibility less effectively than a similar mass of SO_2.

Table 5-1. CALPUFF Modeling Results for Newington Station Unit NT1:
Visibility Improvements from BART Controls

On the 20% Worst Natural Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	0.57	0.45	**0.09**
	1.0%-S residual fuel oil (50% sulfur reduction*)	0.30	0.24	**0.05**
	0.5%-S residual fuel oil (75% sulfur reduction*)	0.46	0.36	**0.07**
	0.3%-S residual fuel oil (85% sulfur reduction*)	0.52	0.40	**0.08**
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	0.47	0.37	**0.08**
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	*<0.05*	*0.03*	***<0.01****
NOx	SNCR (25% NOx reduction**)	0.11	0.10	**0.04**
	SCR (78% NOx reduction**)	0.34	0.30	**0.12**
PM	Baghouse (85% PM reduction**)	0.05	0.04	**0.01**
On the 20% Worst Baseline Visibility Days (deciviews)				
Pollutant	**Control Level**	**Acadia**	**Great Gulf**	**Lye Brook**
SO_2	FGD (90% sulfur reduction*)	**0.13**	**0.10**	<0.01***
	1.0%-S residual fuel oil (50% sulfur reduction*)	**0.07**	**0.06**	<0.01***
	0.5%-S residual fuel oil (75% sulfur reduction*)	**0.11**	**0.09**	0.01
	0.3%-S residual fuel oil (85% sulfur reduction*)	**0.13**	**0.10**	0.01
	0.50 lb SO_2/MMbtu (77% sulfur reduction*)	**0.11**	**0.09**	0.01
	Switch from 0.50 lb SO_2/MMbtu emission limit to 0.3%S residual fuel oil	***0.01***	***0.01***	*<0.01****
NOx	SNCR (25% NOx reduction**)	**0.04**	**0.03**	0.01
	SCR (78% NOx reduction**)	**0.11**	**0.10**	0.03
PM	Baghouse (85% PM reduction**)	**0.02**	**0.02**	<0.01***

* from maximum permitted level
** from baseline level with existing controls
*** below sensitivity limit of model

Note: Values in **boldface** are considered as having greater validity in the modeling estimation of maximum visibility benefits from BART controls.

5.1 CALGRID Modeling Analysis

NHDES also conducted a screening-level analysis of the anticipated visibility effects of BART controls at PSNH Newington Station Unit NT1. Specifically, one modeling run using the CALGRID photochemical air quality model was performed to assess the effects of switching to lower-sulfur fuel for this unit. The simulation covered the full summer modeling episode (from May 15 to September 15, 2002) with MANE-VU's 2018 beyond-on-the-way (BOTW) emissions inventory scenario as a baseline.

The CALGRID model outputs took the form of ambient concentration reductions for SO_2, $PM_{2.5}$, and other haze-related pollutants within the region. NHDES post-processed the modeled concentration reductions to estimate the corresponding visibility improvements at nearby Class I areas (i.e., concentration impacts were converted to visibility impacts).

Based on the CALGRID modeling results, switching to lower-sulfur fuel oil for Unit NT1 is expected to reduce near-stack maximum predicted 24-hour average SO_2 concentration impacts by about 1.4 $\mu g/m^3$. Reductions in the maximum predicted concentrations of SO_2, $PM_{2.5}$, and other haze-related pollutants, combined, would yield negligible visibility improvement at the affected Class I areas.

6. DETERMINATION OF BART

Based on the completed review and evaluation of existing and potential control measures for PSNH Newington Station Unit NT1, it is determined that the NO_X, PM, and SO_2 controls described below represent Best Available Retrofit Technology for this unit.

6.1 Selecting a Pollution Control Plan for NO_X

Use of low excess air reduces NO_X emissions but can often result in greater PM and/or CO emissions. Many of the NO_X reduction benefits acquired through the implementation of low excess air are already being achieved at Unit NT1 through the use of low-NOx burners, overfire air, and water injection; so the application of low excess air would be redundant in this case. Flue gas recirculation reduces the peak flame temperature in much the same way as overfire air and has the additional benefit of reducing the oxygen content in the combustion zone, leading to further reductions in NO_X formation. Because Unit NT1 operates with an existing overfire air system, and because this boiler has already been modified by the installation of natural gas lances, FGR is economically impractical and might also be physically infeasible.

The NO_X emission reductions being achieved at Unit NT1 through the use of combustion control technologies are a substantial improvement over no controls. Retrofitting the facility with SCR or SNCR would reduce NO_X emissions by an additional 300 to 700 tons per year. Despite the sizeable emission reductions that SCR or SNCR would provide, with annualized costs of \$0.7 to \$1.3 million, neither technology option could be implemented cost-effectively. Note that these dollar amounts do not include the significant additional costs of redesigning Newington Station's layout to address spatial constraints. Also, the estimated costs are based on 2002 emission levels, when the plant's capacity factor was around 20 percent. With the capacity factor having fallen to less than 10 percent over the period 2006-

2009, it is difficult to justify additional technology retrofits to reduce NO_X emissions at this facility today. This conclusion is reinforced by the small improvement in visibility that might be obtained with such retrofits on the few occasions when meteorological conditions would indicate maximum impacts.

Another consideration with SCR or SNCR is flue gas and fugitive ammonia emissions. Based on past operation of Unit NT1 and on typical ammonia "slip" rates, it is estimated that fugitive ammonia emissions with either technology would be in the vicinity of 32 tons annually. Ammonia is a regulated toxic air toxic pollutant in New Hampshire and is also a significant contributor to visibility impairment. However, the issue is not so much the magnitude of ammonia slip, toxicity, or visibility impairment as the fact that ammonia slip would occur at all. On balance, this is a relatively minor negative to be weighed in the context of other factors.

Based on all of these considerations, NHDES finds that SCR and SNCR are not cost-effective as Best Available Retrofit Technology for NO_X control at this facility and will not be evaluated further. The existing NO_X controls, which include low-NOx burners, overfire air, and water injection, are determined to fulfill BART requirements for Newington Station Unit NT1.

Because additional retrofits are not proposed, completion of the BART assessment for Unit NT1 becomes a matter of ascertaining this facility's long-term performance capability with existing equipment. NHDES reviewed emissions data for Unit NT1 for the period from 2003 to 2005, when more than 99 percent of the gross heat input came from residual fuel oil. Monthly average NO_X emissions ranged between 0.21 and 0.30 lb/MMBtu. These values compare favorably with the facility's NO_X RACT limit of 0.25 lb/MMBtu, daily average, when burning natural gas and 0.35 lb/MMBtu, daily average, when burning fuel oil. However, the extent of the data record is insufficient to demonstrate that the facility could sustainably meet more restrictive emission limits than these. The current NO_X RACT limitations for Unit NT1 are therefore considered to represent BART control levels.

6.2 Selecting a Pollution Control Plan for PM

PSNH currently operates an electrostatic precipitator on Unit NT1. ESPs perform with removal efficiency rates similar to those of fabric filters but operate at about half the cost for plants of this size. Although it may be technically feasible to improve performance of the existing ESP through some form of upgrade, it is difficult to justify any major capital expense at this facility in light of its recent operating history. Since 2006, the plant's capacity factor has been below 10 percent. In consideration of the facts that Unit NT1 already operates a fully functional ESP, that additional capital outlay for PM control cannot be economically justified at this time, and that any resulting benefit to visibility would be negligible, it is determined that the existing ESP fulfills BART requirements.

The single available stack test on this unit indicates that the ESP yields controlled TSP emission rates in the vicinity of 0.06 lb/MMBtu versus a currently permitted rate of 0.22 lb/MMBtu. The extent of the data record is insufficient to support consideration of a BART performance level more restrictive than the existing permit limit. The facility's Title V operating permit requires that a compliance stack test for PM emissions be performed on Unit NT1 before the permit expires on March 31, 2012. NHDES will review the stack test results to ascertain the unit's performance and incorporate any new limit into a permit amendment by the permit expiration date, as appropriate. The permit expiration date precedes the effective date of proposed BART control measures by fifteen months.

6.3 Selecting a Pollution Control Plan for SO_2

Flue gas desulfurization is a potential SO_2 control option for PSNH Newington Station Unit NT1. However, the cost per ton for FGD on oil-fired boilers is estimated to be about twice the cost of this technology on coal-fired boilers and could well exceed \$1,000/kW for Newington Station. Given the high costs of this option, it is apparent that FGD would be uneconomical as a retrofit for a peak-demand plant the size of Unit NT1.

Use of a lower-sulfur fuel is a practical option for controlling SO_2 emissions at Newington Station. When natural gas is available at reasonable cost relative to residual fuel oil, natural gas is the preferred fuel because of its very low sulfur content. Otherwise, use of low-sulfur residual fuel oil is a reasonable option. For relatively minor increases in the cost of fuel, switching to 1.0%-sulfur or 0.5%-sulfur residual fuel oil would provide significant reductions in fuel sulfur content with proportional reductions in SO_2 emissions.

When not firing exclusively on natural gas, Newington Station Unit NT1 has traditionally burned No. 6 fuel residual fuel oil at 2.0 percent (nominal) sulfur content. From 2002 to 2009, the actual average annual sulfur content of the fuel oil ranged between 1.03 and 1.54 percent by weight, with no significant trend (average fuel sulfur content was 1.21 percent in 2002). For New Hampshire's BART analysis of this plant, the following fuel sulfur values were assumed:

Nominal %S (permit limitation)	Assumed Actual %S (chemical assay)
2.0	1.2
1.0	0.8
0.5	0.4

Under these assumptions, switching from 2.0 %S (nominal) to 1.0 %S (nominal) residual fuel oil would produce a one-third reduction in sulfur dioxide emissions, and switching to 0.5 %S (nominal) residual fuel oil would produce a two-thirds reduction in sulfur dioxide emissions at this facility.

The proposed fuel switching could be accomplished without capital expense and would have predictable costs tied directly to fuel consumption and fuel price differentials. The cost per ton would be no more than about \$1,900 (historical fuel prices suggest a range of \$0 to \$2,000 per ton). At the 2002 production level of 700 million kilowatt-hours, estimated annual costs (long-term average, 2008\$) for switching to 1.0% or 0.5% residual fuel oil would be about \$3.3 or \$6.6 million (equivalent to \$0.0047 or \$0.0094 per kWh), respectively. The cost per kilowatt-hour would vary more or less in proportion to the fuel price differential and would not change significantly with increases or decreases in production level.

While fuel availability is always a consideration, supplies should not be a significant factor in obtaining fuels whose sulfur content is as low as 0.5 percent. Residual fuel oil at 1.0% sulfur is already widely distributed within the region; and there is greater assurance today of the availability 0.5%-sulfur residual fuel oil than in 2008, when New Hampshire began

drafting its BART determinations. Maine, Massachusetts, New Jersey, and other states within MANE-VU are moving toward or already require the use of 0.5%-sulfur residual fuel oil, thus ensuring the presence of a regional market for this commodity.
NHDES considered the possible use of 0.3%-sulfur residual fuel oil for Unit NT1; but this fuel has had only very limited use within the northern New England region, and its future availability and price remain uncertain. More specifically, the fact that some plants in Connecticut are using 0.3%-sulfur residual fuel oil today does not guarantee the availability of this fuel in northern New England, which obtains its bulk oil shipments through different ports.

For Unit NT1, the possible use of low-sulfur residual fuel oil is complicated by the plant's low capacity factor and existing fuel stocks and storage facilities. The plant now has a sizeable quantity of higher-sulfur residual fuel oil in storage tanks on site. Because there is no practical way to offload and replace the existing inventory with a lower-sulfur residual fuel oil, the existing stock of higher-sulfur fuel oil would have to be used up before requiring that Unit NT1 be fired exclusively with low-sulfur fuel oil. Also, it is anticipated that the plant will continue to have a low utilization rate and capacity factor in the coming years (its capacity factor was less than 7 percent in 2009). Given this scenario, depletion of the existing stock of residual fuel oil could take more than a year, or substantially longer if the facility co-fires with natural gas to reduce sulfur dioxide emissions.

EPA has suggested greater use of natural gas and/or low-sulfur distillate fuel oil for Unit NT1 in place of residual fuel oil. The substitution of No. 2 distillate fuel oil for No. 6 residual fuel oil would not be practical for this facility for two major reasons: the high cost of burner replacements needed to implement this option, and the plant's low utilization rate and capacity factor. Unit NT1 would produce relatively few kilowatt-hours of generation through which to recover capital costs.

Greater use of natural gas is a reasonable option when its price is competitive with that of residual fuel oil. Recent years have witnessed sudden and dramatic swings in the price of natural gas relative to fuel oil as supply/demand has shifted. While the future price and availability of natural gas remain difficult to discern, the market for natural gas is expected to expand amid global concerns about carbon emissions and a visible renaissance in gas exploration and development.

Unit NT1 has considerable operational flexibility with respect to fuel selection. The boiler can be fired with either natural gas or liquid fuel as the only fuel, or it can be co-fired with both fuel types simultaneously. However, because of physical limitations to the boiler's design, the unit can operate at no more than about 50 percent of maximum heat input when fueled solely by natural gas. There is already a natural incentive for PSNH to operate Unit NT1 with natural gas as much as possible whenever the price of this fuel is competitive with or less than the price of liquid fuels.

In recognition of the dual-fuel capability of Unit NT1, NHDES has developed for this facility a requirement by rule establishing a new sulfur dioxide emission limitation of 0.50 lb/MMBtu[§] applicable to any fuel type or mix. The recently adopted rule (Attachment GG)

[§] This limit is calculated using USEPA's published AP-42 emission factor for SO_2 of 150(S) lb SO_2/1000 gallons. Assuming 0.5% fuel sulfur content by weight and a heating value of 150,000 Btu/gallon for No. 6 fuel oil, the SO_2 emission rate would be $150 \times 0.5 = 0.075$ lb/gallon, and the SO_2 emission factor would be 0.075

will allow the facility the flexibility to burn natural gas and/or fuel oil in any feasible ratio, depending on market conditions.
New Hampshire's new rule will cause a substantial reduction in SO_2 emissions from Unit NT1 regardless of fuel type while rendering unnecessary any need to speculate on the direction of relative fuel supplies and prices. For the first regional haze progress report, due no later than December 17, 2012, NHDES will review fuel usage, fuel supplies, fuel prices, and plant utilization/capacity factors to determine whether the fuel sulfur limitation described above is still appropriate as BART control for Unit NT1. Should the review indicate a different BART control level, the facility's Title V operating permit will be amended as necessary before its expiration date of March 31, 2012, fifteen months prior to the effective date of proposed BART control measures. The use of low- or ultra-low-sulfur residual fuel oil will be reconsidered as part of this review. Looking beyond 2012, a possible further reduction in the sulfur content of fuel oil burned at this facility would be consistent with MANE-VU's plan to reduce sulfur levels to 0.25-0.5% for all residual fuel oils throughout the region by 2018 (refer to "Statement of the Mid-Atlantic/ Northeast Visibility Union (MANE-VU) Concerning a Course of Action within MANE-VU toward Assuring Reasonable Progress," June 20, 2007, included in Attachment E).

7. SUMMARY AND CONCLUSIONS

Table 7-1 summarizes Best Available Retrofit Technology for PSNH Newington Station Unit NT1 for the pollutants NO_X, PM, and SO_2. The summary includes existing controls that have been determined to fulfill BART requirements as well as new operating conditions consistent with BART requirements. A more stringent sulfur dioxide emission limitation, established by a rule change, will require the facility to reduce average fuel sulfur content through appropriate adjustments to its fuel mix.

Table 7-1. Summary of BART Determinations for Unit NT1

Pollutant	Current Emission Controls	BART Controls	BART Emission Limit
NO_X	Low-NOx burners, overfire air, and water injection	Low-NOx burners, overfire air, and water injection	0.35 lb/MMBtu (oil) and 0.25 lb/MMBtu (oil/gas), daily avg. (= RACT limit)
PM	ESP	ESP	0.22 lb/MMBtu total suspended particulate (TSP)
SO_2	2.0% sulfur content limit on residual fuel oil; 0.4% sulfur content limit on distillate fuel oil	SO_2 emission limitation of 0.50 lb/MMBtu, applicable to any fuel type or mix	0.50 lb/MMBtu, 30-day rolling average

lb/gallon ÷ 150,000 BTU/gallon × 10^6 = 0.5 lb/MMBtu.

NEW HAMPSHIRE BART ANALYSIS: Newington Station Unit NT1 (400 MW)

Pollutant	Emission Control Technology	Approx. Control Level	Uncontrolled Emissions ton/yr	Controlled Emissions ton/yr	Emission Reductions ton/yr	Estimated Cost of Emission Controls[6]					
						Capital $	Capital $/kW	O&M $/yr	Total Annual $/yr	Average $/ton	Ref./ Note
NO_X	Combustion Controls (existing)	33%	1,407 [1]	943 [2]	464	—	—	—	—	—	
	LNB (typical)	40%	1,407 [1]	844	563	7,905,617	20	167,052	829,306	1,473	7
	LNB+OFA (typical)	50%	1,407 [1]	704	704	10,732,574	27	228,215	1,127,283	1,602	7
	SCR	85%	1,407 [1]	211	1,196	11,510,100	37	441,685	1,405,886	1,175	7
	SNCR	50%	1,407 [1]	704	704	3,298,475	12	451,026	727,339	1,034	7
PM	ESP (existing)	42%	338 [2]	196 [2]	142	—	—	—	—	—	
	Fabric Filters	99%	338 [2]	3	335	min. 23,426,952	59	2,733,144	4,695,620	14,033	8
						max. 78,089,840	195	3,904,492	10,446,078	31,218	
SO_2	2.0%-S oil (existing)	0% [3]	5,226 [2]	—	—	—	—	—	—	—	
	Switch to 1.0%-S oil	33% [4]	5,226 [2]	3,484	1,742	—	—	—	3,310,808	1,901	9
	Switch to 0.5%-S oil	67% [5]	5,226 [2]	1,742	3,484	—	—	—	6,621,615	1,901	10
	FGD	90%	5,226 [2]	523	4,703	422,000,000	1,055	unknown	unknown	unknown	11

1 Estimated.

2 2002 (baseline) emissions reported in NHDES data summary as derived from facility's annual emissions statement.

3 Actual average fuel sulfur content was ~1.2% in 2002. Over period 2002-09, average annual values ranged from 1.03 to 1.54% S with no significant trend.

4 Based on an assumed average fuel sulfur content of 0.8%.

5 Based on an assumed average fuel sulfur content of 0.4%.

6 All cost estimates adjusted to 2008$.

7 USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

8 NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

9 Stated costs represent premium for purchasing 1.0%-S oil at estimated price differential of 7.5¢/gal.

10 Stated costs represent premium for purchasing 0.5%-S oil at estimated price differential of 15¢/gal.

11 Based on $/kW estimated capital cost for comparable controls at Merrimack Station.

Newington Station Unit NT1: NO_X Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

Costs: 2004$

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
LNB	19.24	17.4	6,940,840	581,434	0.29	0.26	104,618	0.06	42,048	146,666	728,100	563	1,293
LNB+OFA	26.12	23.6	9,422,804	789,348	0.40	0.36	144,300	0.08	56,064	200,364	989,713	704	1,406
SCR	32.20	25.26	10,105,443	846,533	0.99	0.78	310,695	0.11	77,088	387,783	1,234,316	1,196	1,032
SNCR	10.80	7.24	2,895,939	242,593	0.17	0.11	45,584	0.50	350,400	395,984	638,577	704	907

Costs: 2008$ 2004$ $\rightarrow$ 2008$ 1.139 multiplier

Control Technology	Capital	Scaled Capital	Total Capital	Total Annualized Capital	Fixed O&M	Scaled Fixed O&M		Variable O&M		Total Fixed & Variable O&M	Total Annualized Cost	Emission Reductions	Average Cost
	$/kW	$/kW	$	$/yr	$/kW/yr	$/kW/yr	$/yr	mills/kWh	$/yr	$/yr	$/yr	tons/yr	$/ton
LNB	21.91	19.76	7,905,617	662,254	0.33	0.30	119,160	0.07	47,893	167,052	829,306	563	1,473
LNB+OFA	29.75	26.83	10,732,574	899,068	0.46	0.41	164,358	0.09	63,857	228,215	1,127,283	704	1,602
SCR	36.68	28.78	11,510,100	964,201	1.13	0.88	353,882	0.13	87,803	441,685	1,405,886	1,196	1,175
SNCR	12.30	8.25	3,298,475	276,313	0.19	0.13	51,920	0.57	399,106	451,026	727,339	704	1,034

Cost Reference:

USEPA, *Documentation for EPA Base Case 2006 (V.3.0) Using the Integrated Planning Model*, November 2006.

Note: Cost estimates for LNB and LNB+OFA are based on referenced values for coal-fired plants; actual costs could be greater for oil- or gas-fired units.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Newington Station Unit NT1: PM Controls

Plant type	oil- or natural-gas-fired boiler	
Capacity	400	MW
Maximum heat Input	4,350	MMBtu/hr
Capacity factor	20	%
Annual hours	8,760	hr/yr
Annual production	700,800,000	kWh/yr
Flue gas flow rate	1,714,000	acfm

Historical operation:

Year	2002	2003	2004	2005	2006	2007	2008
Operating hours	3,085	6,606	6,300	4,187	1,282	1,374	548
Total Heat Input*	7,223,832	26,414,481	22,477,521	16,060,698	3,600,581	4,303,867	1,231,841
Capacity factor**	19.0%	69.3%	59.0%	42.1%	9.4%	11.3%	3.2%

*MMBtu (from CEM data) **Based on ratio of total heat input to theoretical maximum heat input

2004$

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	15.00	25,710,000	2,153,727	0.25	0.45	1,199,800	3,353,527	142	23,616
	max.	40.00	68,560,000	5,743,271	0.65	0.60	2,142,500	7,885,771	142	55,534
Wet ESP	min.	15.00	25,710,000	2,153,727	0.15	0.25	685,600	2,839,327	142	19,995
	max.	40.00	68,560,000	5,743,271	0.50	0.50	1,714,000	7,457,271	142	52,516
Fabric Filter - Reverse Air	min.	17.00	29,138,000	2,440,890	0.35	0.70	1,799,700	4,240,590	335	12,673
	max.	40.00	68,560,000	5,743,271	0.75	0.80	2,656,700	8,399,971	335	25,103
Fabric Filter - Pulse Jet	min.	12.00	20,568,000	1,722,981	0.50	0.90	2,399,600	4,122,581	335	12,320
	max.	40.00	68,560,000	5,743,271	0.90	1.10	3,428,000	9,171,271	335	27,408

Cost Reference:

NESCAUM, *Assessment of Control Technology Options for BART-Eligible Sources*, March 2005.

Annualized cost basis:

Period, yrs	15
Interest, %	3.0
CRF	0.08377

Costs: 2008$ 2004$ → 2008$ 1.139 multiplier

Control Technology		Capital $/acfm	Total Capital $	Total Annualized Capital $/yr	Fixed O&M $/yr-acfm	Variable O&M $/yr-acfm	Total Fixed & Variable O&M $/yr	Total Annualized Cost $/yr	Emission Reductions tons/yr	Average Cost $/ton
Dry ESP	min.	17.09	29,283,690	2,453,095	0.28	0.51	1,366,572	3,819,667	142	26,899
	max.	45.56	78,089,840	6,541,586	0.74	0.68	2,440,308	8,981,893	142	63,253
Wet ESP	min.	17.09	29,283,690	2,453,095	0.17	0.28	780,898	3,233,993	142	22,775
	max.	45.56	78,089,840	6,541,586	0.57	0.57	1,952,246	8,493,832	142	59,816
Fabric Filter - Reverse Air	min.	19.36	33,188,182	2,780,174	0.40	0.80	2,049,858	4,830,032	335	14,434
	max.	45.56	78,089,840	6,541,586	0.85	0.91	3,025,981	9,567,567	335	28,592
Fabric Filter - Pulse Jet	min.	13.67	23,426,952	1,962,476	0.57	1.03	2,733,144	4,695,620	335	14,033
	max.	45.56	78,089,840	6,541,586	1.03	1.25	3,904,492	10,446,078	335	31,218

Newington Station Unit NT1: SO_2 Controls

SO_2 Control Cost Calculations for Switching from #6 Fuel Oil @ 2.0% S to Lower-Sulfur Fuel Oils @ 1.0 or 0.5% S:

Fuel Type	Maximum (Nominal) Fuel Sulfur[1]	Actual Fuel Sulfur	Annual Fuel Usage[4]	Annual SO_2 Emissions	Switch to Lower-S Fuel	Annual SO_2 Emission Reductions[7]	Blended Fuel Price Differential[8]		SO_2 Control Cost
	%S by wt	%S by wt	gal/yr	ton/yr	%S by wt	ton/yr	¢/gal	$/yr	$/ton removed
#6 Residual Oil	2.0	1.2 [2]	44,144,100	5,226 [5]	—	—	—	—	—
#6 ULS Residual Oil	1.0	0.8 [3]	44,144,100	3,484 [6]	2.0 to 1.0%	1,742	7.5 [9]	$3,310,808	$1,901
#6 ULS Residual Oil	0.5	0.4 [3]	44,144,100	1,742 [6]	2.0 to 0.5%	3,484	15.0 [10]	$6,621,615	$1,901

[1] Maximum allowable sulfur content of specified fuel.

[2] Actual average sulfur content of fuel burned in 2002. In the period 2002-09, average annual values ranged from 1.03 to 1.54% S with no significant trend.

[3] Assumed average sulfur content of specified fuel as assayed.

[4] Actual fuel usage in 2002.

[5] Actual 2002 emissions from CEM data.

[6] Estimated emissions based on stated fuel usage and estimated average sulfur content of specified fuel.

[7] Estimated emission reductions after switch to specified lower-sulfur fuel.

[8] Estimated price difference between residual oil @ >1.0%S and residual oil @ ≤1%S, based on EIA fuel price data for all U.S. locations, 1983-2008.

[9] Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.8%S actual (1.0% nominal).

[10] Estimated price difference between fuel @ 1.2%S (2002 actual) and fuel @ 0.4%S actual (0.5% nominal).

SO_2 Control Cost Calculations for Flue Gas Desulfurization:

As an approximation, assume that FGD capital cost for Newington Station would be comparable to that for Merrimack Station on a $/kW basis.

Merrimack Station has an estimated capital cost of $1,055/kW, based on PSNH's 2008 estimate of $457 million for Unit MK1 (113 MW) and Unit MK2 (320 MW) combined.

Newington Station Unit NT1 has a generating capacity of 400 MW (=400,000 kW).

Estimated capital cost for FGD on Unit NT1 = 400,000 kW × $1,055/kW = $422,000,000.

Enclosure to Letter from PSNH to DES ARD, dated 12/4/09

NOTE: This sheet is a re-creation of PSNH's tables, with formulas inserted and additional calculations. All changes and additions to the original are shown in blue.

Assumptions Used to Calculate Incremental Cost Estimates*

(A) % sulfur	AP-42** SO2 lb/1000gal	AP-42*** SO2 lb/mmbtu	(B) SO2 lb/mmbtu	(C) Max Gross Heat Input mmbtu/hr	(D) SO2 lb/hr	(E) Reduction in SO2 lb/hr	Fuel Switch	increased cost/barrel**** low	increased cost/barrel**** high	increased cost/hr***** low	increased cost/hr***** high	$/ton SO2 Reduced low	$/ton SO2 Reduced high
2.0	314.0	2.041	2.288	4,350	9,952.8								
1.0	157.0	1.021	1.086	4,350	4,724.1	5,228.7	2% to 1%	$0.00	$4.00	$0.00	$2,692.86	$0	$1,030
0.7	109.9	0.714	0.748	4,350	3,253.8	1,470.3	1% to 0.7%	$1.00	$3.30	$673.21	$2,221.61	$414	$3,022
0.5	78.5	0.510	0.528	4,350	2,296.8	957.0	0.7% to 0.5%	$1.00	$2.20	$673.21	$1,481.07	$586	$3,095
0.3	47.1	0.306	0.313	4,350	1,361.6	935.3	0.5% to 0.3%	$3.00	$9.00	$2,019.64	$6,058.93	$2,967	$12,957
				4,350		5,228.7	2% to 1%	$0.00	$4.00	$0.00	$2,692.86	$0	$1,030
				4,350		6,699.0	2% to 0.7%	$2.00	$7.00	$1,346.43	$4,712.50	$402	$1,407
				4,350		7,656.0	2% to 0.5%	$3.00	$9.00	$2,019.64	$6,058.93	$528	$1,583
				4,350		8,591.3	2% to 0.3%	$4.00	$17.00	$2,692.86	$11,444.65	$627	$2,664

(A) % sulfur in the fuel oil
(B) SO2 lb/mmBtu emission rate, calculated based on %S and 153,846 btu/gal
(C) Maximum gross heat input rate from permit
(D) SO2 lb/hr emission rate, calculated = B * C
(E) Lbs of SO2 reduced per hour

** Source: USEPA, Compilation of Air Pollutant Emission Factors, AP-42, 5th Ed., Vol. 1. Section 1.3 - Fuel Oil Combustion (9/98)
*** Based on fuel heating value of 153,846 BTU/gal
**** From historical fuel cost table, approximate.
***** $/barrel ÷ 42 gal/barrel ÷ 0.153846 mmBTU/gal × mmBTU/hr = $/hr

	Actual Fuel Use #6 oil (barrels)	Historical Fuel Cost 2%S Oil ($/barrel)	1%S Oil ($/barrel)	0.7%S Oil ($/barrel)	0.5%S Oil ($/barrel)	0.3%S Oil ($/barrel)
2002	1,051,050	$21.20	$22.45	$23.26	$23.80	$25.25
2003	3,425,217	$24.95	$27.48	$29.26	$30.45	$32.63
2004	3,099,258	$25.25	$27.92	$30.04	$31.46	$34.53
2005	2,027,172	$37.00	$41.00	$44.00	$46.00	$50.10
2006	392,922	$45.50	$46.30	$48.46	$49.90	$54.12
2007	529,092	$53.70	$53.45	$56.54	$58.60	$62.86
2008	201,172	$75.25	$77.80	$81.10	$83.30	$92.16
2009	118,246	$49.90	$50.75	$51.98	$52.80	$55.83

Historical fuel cost data from Platts 2002-2009.
2009 data includes costs through 9/09 only.

*Estimates calculated illustrate cost increases based on assumptions relied upon.

chm
12/08/09

Supporting Documentation for BART Analyses

- PSNH Correspondence, December 4, 2009
- PSNH Correspondence, July 9, 2010
- PSNH Correspondence, August 16, 2010
- PSNH Correspondence, December 15, 2010

Public Service of New Hampshire

PSNH Energy Park
780 North Commercial Street, Manchester, NH 03101

Public Service Company of New Hampshire
P.O. Box 330
Manchester, NH 03105-0330
(603) 634-2236
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macdojm@psnh.com

The Northeast Utilities System

John M. MacDonald
Vice President - Generation

December 4, 2009

Mr. Robert R. Scott, Director
Air Resources Division
Dept. of Environmental Services
29 Hazen Drive, PO Box 95
Concord, NH 03302-0095

Public Service Company of New Hampshire
Request for Additional Information for Determination of
Best Available Retrofit Technology (BART) for the NH Regional Haze SIP

Dear Mr. Scott:

In response to your request, dated November 17, 2009, for additional information necessary to finalize the NH Department of Environmental Services, Air Resources Division's response to comments received from the U.S. Environmental Protection Agency and Federal Land Managers specific to DES' Best Available Retrofit Technology (BART) demonstration, Public Service Company of New Hampshire is submitting the enclosed information.

As you know, PSNH did not submit written comments specific to DES' BART determination presented at the public hearing on June 24, 2009, because PSNH was in agreement with that determination. PSNH is interested in understanding the basis of any significant changes to the BART determination and would raise objection to overly stringent BART limits that provide minimal environmental benefit yet increase costs and expose PSNH's generating facilities to permit exceedances during the course of normal operation of the units.

<u>Incremental Cost Estimates of SO2 Reductions at Newington Unit NT1</u>

In order to estimate incremental costs associated with varying grades of oil, PSNH evaluated historical fuel cost data provided by Platts for the period of 2002 through September 2009. Considering the inevitable inaccuracies in trying to predict future fuel prices, PSNH has calculated incremental cost estimates for illustrative purposes using the more recent historical fuel cost data (2005-2009).

As illustrated on the enclosed spreadsheet, PSNH has estimated the incremental costs, on a dollar per ton basis, of sulfur dioxide reductions at Newington Station, Unit NT1 to be as follows:

2% sulfur content by weight to 1% sulfur content by weight	\$1,030 per ton SO2 reduced
1% sulfur content by weight to 0.7% sulfur content by weight	\$2,949 per ton SO2 reduced
0.7% sulfur content by weight to 0.5% sulfur content by weight	\$7,203 per ton SO2 reduced
0.5% sulfur content by weight to 0.3% sulfur content by weight	\$12,957 per ton SO2 reduced

Assumptions Used to Produce Estimated Incremental Costs

The assumptions used to estimate incremental costs include historical fuel prices, maximum gross heat input rate of Unit NT1, SO2 emission rates in lb/mmBtu and lb/hr for each grade of fuel, and tons of SO2 reduced. Capacity factor of Unit NT1 is not necessary to calculate incremental costs on a dollar per ton reduced basis. The SO2 emission rates were derived from the sulfur content of the fuel, the heating value of the fuel, and the maximum gross heat input rate of Unit NT1. The tons of SO2 reduced were calculated using the delta in SO2 emissions between each fuel type on a lb/hr basis which was calculated using the SO2 lb/mmBtu emission rate for each grade of fuel and the maximum gross heat input rate of Unit NT1 as contained in Newington Station's Title V Operating Permit, TV-OP-054.

Additional Costs Associated with Fuel Storage Upgrades at Newington Station

At the present time, PSNH is hopeful that the current fuel storage and delivery system, including configuration and storage capacity, is adequate to handle varying grades of oil if required in the future. As a result, PSNH has not calculated additional costs associated with fuel storage upgrades.

MK Unit #2 Boiler and SCR Operations

The SCR has a temperature permissive that must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and low load operation of Merrimack Unit #2, the temperature is lower than that permissive temperature and the SCR cannot be operated. As an example, Merrimack Unit 2 typically has 10 to 15 outages per year, in addition to approximately 8 low load operating periods per year. The timing of these conditions is not predictable and this estimate of occurrences provided reflects historical performance. Examples of low load situations include, but are not limited to: forced and planned outage start ups and shutdowns, loss of one of any equipment pair where both pieces of equipment are necessary for full load operation and the loss of one results in half load operation (such as Forced Draft Fans, Condensate Pumps), loss of the Main Boiler Feed Pump, loss of coal feeders, condenser waterbox cleaning, etc. Any condition which requires the unit be at loads below 230 mw net, causing the temperature to be below the SCR permissive will result in the SCR not able to be put in service. This load point may increase with the new, more efficient HP/IP turbine.

In addition to boiler operations and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

As part of normal service, the SCR catalyst becomes coated with flyash. Blinding of the catalyst with flyash can cause the SCR process control settings (often referred to as the setpoint) to have to be increased (less NOx conversion), as the reagent distribution becomes less uniform and as less catalyst is exposed to the flue gas. The SCR is cleaned as needed during outages, and sootblowers are used on line.

Reagent injection grid nozzles, being in the flue gas path, can become fouled with deposits. This can affect reagent distribution, compounding the effect of a fouled catalyst, for example. The reagent injection grid is cleaned, as needed, during outages. Also, reagent delivery disruption can occur and on-site storage is limited.

Also as a catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emission because the SCR has four layers of catalyst, staggered in age. However, it will compound the effect of a fouled catalyst, for example.

The uncontrolled NOx rate at reduced load and during start ups and shut-downs is typically 1.0 - 1.5 lb NOx/mmBTU. The uncontrolled NOx rate at normal full load is as high as 2.66 lb NOx/mmBTU, with an average of 2.4 lb NOx/mmBTU.

The SCR is unable to perform continually at its maximum capability due to these concerns. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions.

In closing, PSNH would like to reiterate its opinion that changes to DES' BART determination that result in more stringent emissions limitations create concerns relative to increased costs and decreased operational flexibility.

Please contact Laurel L. Brown, Senior Environmental Analyst – Generation, at 634-2331 if you would like additional information or would like to meet to discuss the enclosed information further.

Sincerely,

John M. MacDonald
Vice President – Generation

Enclosure

Assumptions Used to Calculate Incremental Cost Estimates*

(A) % sulfur	(B) SO2 lb/mmbtu	(C) Max Gross Heat Input mmbtu/hr	(D) SO2 lb/hr	(E) Reduction in SO2 lb/hr		increased cost/barrel low	increased cost/barrel high	increased cost/hr low	increased cost/hr high	$/ton SO2 Reduced
2.0	2.288	4,350	9,952.8							
1.0	1.086	4,350	4,724.1	5,228.7	2% to 1%	0	$ 4.00	0	$ 2,692.86	$ 1,030
0.7	0.748	4,350	3,253.8	1,470.3	1% to 0.7%	$ 1.00	$ 3.30	$ 673.21	$ 2,167.75	$ 2,949
0.5	0.528	4,350	2,296.8	957.0	0.7% to 0.5%	$ 1.00	$ 2.20	$ 673.21	$ 3,446.86	$ 7,203
0.3	0.313	4,350	1,361.6	935.3	0.5% to 0.3%	$ 3.00	$ 9.00	$ 2,019.64	$ 6,058.93	$ 12,957

(A) % sulfur in the fuel oil
(B) SO2 lb/mmBtu emission rate, calculated based on %S and 153,846 btu/gal
(C) Maximum gross heat input rate from permit
(D) SO2 lb/hr emission rate, calculated = B * C
(E) Lbs of SO2 reduced per hour

	Actual Fuel Use	Historical Fuel Cost				
	#6 oil (barrels)	2%S oil ($/barrel)	1%S oil ($/barrel)	0.7%S oil ($/barrel)	0.5%S oil ($/barrel)	0.3%S oil ($/barrel)
2002	1,051,050	$ 21.20	$ 22.45	$ 23.26	$ 23.80	$ 25.25
2003	3,425,217	$ 24.95	$ 27.48	$ 29.26	$ 30.45	$ 32.63
2004	3,099,258	$ 25.25	$ 27.92	$ 30.04	$ 31.46	$ 34.53
2005	2,027,172	$ 37.00	$ 41.00	$ 44.00	$ 46.00	$ 50.10
2006	392,922	$ 45.50	$ 46.30	$ 48.46	$ 49.90	$ 54.12
2007	529,092	$ 53.70	$ 53.45	$ 56.54	$ 58.60	$ 62.86
2008	201,172	$ 75.25	$ 77.80	$ 81.10	$ 83.30	$ 92.16
2009	118,246	$ 49.90	$ 50.75	$ 51.98	$ 52.80	$ 55.83

Historical fuel cost data from Platts 2002-2009
2009 data includes costs through 9/09 only.

* Estimates calculated illustrate cost increases based on assumptions relied upon.

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The Northeast Utilities System

CONFIDENTIAL Released per Nov 3, 2010 letter to PSNH

July 9, 2010

RCVD via e-mail on July 16, 2010

Michele Roberge
Administrator, Permitting and Environmental Health Bureau
NH Department of Environmental Services, Air Resources Division
29 Hazen Drive
PO Box 95
Concord, NH 03302-0095

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NEW HAMPSHIRE
JUL 16 2010
AIR RESOURCES DIVISION

CONFIDENTIAL ~~BUSINESS~~ INFORMATION

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

Dear Ms. Roberge:

As requested, PSNH provides the following information to support the Merrimack Unit #2 (MK2) NOx limits and the Newington (NT1) fuel oil sulfur content for New Hampshire's Regional Haze SIP. We are providing this information as confidential business information since it contains various operating scenarios and financial costs which are competitively sensitive in nature and could be harmful if disclosed.

Merrimack Station Unit #2: Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers and the associated costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP

1. Operating Temperature of SCR

As previously provided, the SCR has a temperature permissive that must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and low load operation of Merrimack Unit #2, the temperature is lower than that permissive temperature and the SCR cannot be operated. For example, Merrimack Unit 2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are less than the permissive temperature rendering the SCR inoperable. The timing of these events is not predictable; the estimate of occurrences provided reflects historical performance.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;

- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

2. Malfunction and Fouling of the SCR and/or Associated Equipment

In addition to boiler operations and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

Also as part of normal service, the SCR performance degrades over time. One reason this occurs is due to blinding of the catalyst with fly ash. This condition will cause the SCR process control settings to compensate by increasing SCR loading to maintain the set point. This is necessary because the reagent distribution becomes less uniform as less surface area of the catalyst is exposed to the flue gas. To manage this condition from developing to the point that a maintenance outage is necessary, the SCR is cleaned on-line utilizing soot blowers and cleaned during outages, as needed. Increased SCR loading will lead to more frequent maintenance outages. Reagent injection grid nozzles are directly exposed to the flue gas and become fouled over time. This can affect reagent distribution, compounding the effect of a fouled catalyst. The reagent injection grid is cleaned, as needed, during outages. Also as catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emissions because the SCR has four layers of catalyst, intentionally staggered in age. However, it will compound the effect of a fouled catalyst and can result in the SCR being unable to perform continually at its maximum capability. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions. Currently the SCR averages greater than 86% efficiency. The uncontrolled NOx rate at normal full load is as high as 2.66 lb NOx/mmBTU, with an average of 2.4 lb NOx/mmBTU. The uncontrolled NOx rate at reduced load and during start ups and shut-downs is typically 1.0 - 1.5 lb NOx/mmBTU.

With these short-term challenging operational conditions, PSNH's greatest concern is ensuring consistent compliance. We have reviewed historical data and concluded that start-ups and shut downs can significantly impact both a calendar month and a rolling 30-day average emission rate by up to 0.04 lb NOx/mmBTU. If there is more than 1 outage during the averaging period, the impact to the average emission rate could be as high as 0.08 lb NOx/mmBTU. To allow for this potential operating occurrence, Merrimack Station would need to operate to maintain a much lower average NOx rate. Reviewing the historical monthly averages, this leaves little margin for typical operating fluctuations in NOx controls. For example, if a unit is off for a longer period of time, there are less valid operating days available to be included in average rate. This analysis is particularly interesting, because in this specific scenario, the total tons of emissions are less than full load operation for the same averaging period, but could have a high emission rate. An extreme example of this scenario was observed in August 2009 when the monthly average emission rate was 0.813 lb NOx/mmBTU and yet total emissions for that month were approximately 1 ton. This was primarily due the unit operating only a short amount of time in that month.

3. Potential Costs Associated with Proposed Reduction in NOx emission rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with short-term events as described above and the operational restrictions of the SCR. Each has an additional cost as outlined below.

There will be increased maintenance costs to maintain peak NOx reduction capability. For example, air heater cleanings will be required more frequently because of increased loading of the SCR. This scenario results in additional maintenance costs and replacement power costs associated with the required outages.

Maintenance (Cleaning) Costs: $30,000 to $100,000 per cleaning

Replacement Power Costs: The table below uses an assumption of ~ $30/mwhr difference between the cost of Merrimack Station and the market cost. This number can vary greatly depending on energy market prices.

Duration of Cleaning/Outage	Replacement Power Cost per Outage	Number of outages per year	Total Cost per Year
Short (3 days)	$720,000	1 2 3 4	$720,000 $1,440,000 $2,160,000 $2,880,000
Mid (4.5 days)	$1,100,000	1 2 3	$1,100,000 $2,200,000 $3,300,000
Long (6 days)	$1,400,000	1 2	$1,400,000 $2,800,000

If air heater washings were routinely necessary to comply with a step change in the NOx rate, the cost per ton of NOx reduction would be extremely costly, as illustrated below. This cost can increase greatly if an air heater cleaning was completed during a high priced market.

Emission Rate Lb NOx/mm BTU	NOx tons emitted per year	Incremental tons per year	Incremental tons per day
0.37	5628.34		
0.34	5171.99	456.35	1.25

Duration of Cleaning/Outage	Replacement Power Cost per Outage	Incremental tons per year	Cost per Ton
Short (3 days)	$720,000	456.35	$1,578
Mid (4.5 days)	$1,100,000	456.35	$2,410
Long (6 days)	$1,400,000	456.35	$3,068

Examples of other compliance measures that would be necessary include accelerating the catalyst replacement in the SCR management plan. Currently, one layer of catalyst is exchanged every 2 years. To revise this plan by exchanging one layer every year would result in a project expense of approximately $2 million every other year. Increasing the frequency of catalyst replacement would result in approximately $12 million over the period 2013 thru 2025. This revised replacement plan would not likely result in additional total reduced tons of NOx for the year, but rather help manage the brief periodic increased emission rates associated with the events described above.

It should be reiterated that these compliance measures are focused solely on the shorter duration events that typically occur at lower loads with less heat input and for a discreet period of time-- and thus do not result in the emission of a significant amount NOx emissions. For example, the flexibility of partial load operation during high demand periods is important to the electrical reliability of the grid and can significantly protect customers from high energy costs during these peak events. It would not be in the public interest to require the unit to come off line since such action would be extremely costly to both reliability and to customers. A half day of no operation when energy prices are over $100mwh will be $250,000, $350,000 or greater; a cost that would yield a NOx reduction of only approximately 10 – 15 tons.

This discussion demonstrates that the implementation of a calendar month and rolling 30 day lb/mmbtu NOx emission rate can result in significant cost to our customers with little environmental benefit. To avoid permit exceedences due to a short-term NOx rate excursion, would require running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages.

Replacement power cost associated with outages:

	Cost delta with the Market	Total cost of Outage for customers	Cost per Ton *
1 day	$30	$239,040	$15,936
	$40	$318,720	$21,248
	$50	$398,400	$26,560
2 days	$30	$478,080	$15,936
	$40	$637,440	$21,248
	$50	$796,800	$26,560

*assumes saving of 15 tons per day

As you are aware, Merrimack Station has aggressively reduced NOx emissions for the past 15 years. The total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable, affordable power, but to do that successfully, we do require operational flexibility. It is critical to understand that such operational flexibility will ensure consistent compliance with the monthly average emission rate while not significantly increasing total NOx emissions.

Newington Station- additional fuel oil information

In your June 15, 2010 email, you also requested information regarding Newington Station's current oil stocks, storage capacity, fuel usage rates, and operational considerations and costs associated with switching to lower sulfur fuels required by the NH Regional Haze SIP. That information is provided below.

Please describe the current oil stocks (type and quanitiy) and storage capabilities.

Newington Station has the capacity to store approximately 732,500 barrels (31 million gallons) of fuel oil in four separate above ground storage tanks (identified as NT-1, NT-2, SR-2, and SR-3). Currently, these four tanks contain approximately 485,000 barrels (20 million gallons) of No. 6 fuel oil with an average sulfur concentration of approximately 1%.

How many hours of operation would this supply at current usage rates? What are the rates that this estimate is based on?

Due to various economic conditions, including the rising cost of No. 6 fuel oil, lower natural gas prices and electric demand, Newington Station has burned only a limited volume of oil in the past couple years. Current conditions are not expected to change considerably in the short term, therefore, Newington does not anticipate consuming a significant volume of oil in the next couple of years.

It is difficult to assess how long it would take to deplete this fuel oil inventory since fuel oil usage is dependent on market conditions and the demand for electricity. Newington Station will choose the fuel or blend of fuel (oil, natural gas, or natural gas and oil) based on the desired electrical output and the cost of fuel. As you are aware, Newington Station will use the most cost effective fuel to maintain its electric costs for the customer.

In an effort to understand how this inventory relates to future operating conditions, PSNH has looked at different operating scenarios to estimate the length of time it may take to deplete this inventory. The scenarios include different operating loads, a fuel mix of 75% natural gas and 25% fuel oil, and an operating capacity factor of 5% (see table below). Although, PSNH can not reliably predict with any certainty how Newington Station will operate in the next couple years, for purposes of this evaluation, PSNH has assumed an average output level of 150 MW with a heat rate of 11,750 Btu/kWh, 75% natural gas/25% oil blend, and a capacity factor of 5%.

Based on current fuel oil inventory levels, and the scenario presented above, Newington Station would deplete its existing fuel supply in 16 years.

MW	Btu/kWh	Btu/gal Oil	Capacity Factor %	BBl/yr	75% gas/25% oil BBl/yr	Projected depletion of current inventory (yrs)
400	10,793	153,846	5	292,645	73,161	7
150	11,750	153,846	5	119,533	29,883	16
100	13,860	153,846	5	93,951	23,488	21
60	16,560	153,846	5	67,352	16,838	29

Note:
Assuming an average output level of 150 MW with a heat rate of 11,750 Btu/kWh, a 75%/25% gas/oil blend, and a capacity factor of 5%, the current inventory would be depleted in 16 years. This scenario is Newington Station's best estimate based on current operating history.

What are the specific operational considerations in switching to 0.3% S oil that do or do not make it feasible and costly?

PSNH understands that the Regional Haze SIP will require Newington Station to burn 0.5% or 0.3 % sulfur oil as part of its compliance strategy as early as 2013. In order to prepare for this requirement, Newington Station would need to have the available capacity to store the lower sulfur oil. Due to a variety of factors that affect the availability and cost of natural gas, PSNH believes it would be necessary to empty one of the larger bulk fuel oil storage tanks, at a minimum, to provide the storage capacity of the lower sulfur fuel. Our largest tanks (NT1 and NT-2) currently contain approximately 160,000 barrels each of fuel oil. Based on the likely operating scenario presented above, it will take more than 5 years to empty one of the larger tanks.

In this scenario, Newington would either need to operate and utilize the on-hand fuel or sell some of its current inventory if an acceptable process could be identified. It is difficult to estimate what the cost to PSNH would be if this were required, since the value of this oil in 3 years is unknown.

PSNH currently knows of no way other than consuming oil in the unit to dispose/deplete our current inventory. Although offloading oil from the tanks to a barge or ship is being considered, Newington's oil terminal was designed to accept deliveries of oil from fuel vessels and was not designed to load vessels from the oil tanks. Newington Station also does not have the capability for loading trucks from the oil tanks. Any risk to personnel safety or the environment would need to be fully eliminated to consider a transfer of oil to a vessel or truck. Therefore, at this point, it is assumed that Newington Station would be required to burn the oil in the unit at a potential incremental cost to NH customers. Consistent with the numbers above, to burn 160,000 barrels of oil to empty one of the larger tanks, the unit would have to operate an equivalent of 24 hours/day for approximately 10 days at 400 MWs. Also, as stated above, due to economic conditions, Newington Station has been reserved to protect customers from high priced market excursions. If we assume consumption of the inventory of oil is required, then it will be necessary for Newington to operate at rates higher than market rates. In this case, based on an incremental cost of $80 per MWH, the total cost to customers will be approximately $8 million. This is a significant cost to customers which has no associated environmental benefit.

Blending this higher sulfur fuel with lower sulfur fuel or natural gas over time is a more cost effective option and will not result is greater emissions as compared to a targeted depletion effort described in the above scenario. Although it is possible to consider the depletion of current fuel oil inventories by blending with natural gas, natural gas is not always available and could not be relied upon as a sole compliance option.

What are the estimated costs of making the switch; both capital and operating costs?

As presented in our earlier December 4, 2009 letter, the cost to PSNH in going from a 1% sulfur oil to a 0.5% sulfur oil could be as high as $42/bbl (based on fuel oil prices from 2005-2009). Similarly, the cost to PSNH in going from 1% sulfur oil to 0.3% sulfur oil could be as high as $51/bbl. Using the same operating scenario presented above, this equates to an additional cost to PSNH customers of $1.2 million/year for the use 0.5% sulfur fuel and $1.5 million/year for the use 0.3%.

PSNH would be happy to meet with you and your staff to discuss the information provided above. If you have questions or require additional information, please contact me at 634-2440 or Sheila Burke at 634-2512.

Sincerely,

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Technical Business Manager -- Generation

cc:
Sheila Burke, Generation Staff
Tara Olson, Newington Station

Released Per Nov3, 2010 Letter to PSNH

August 16, 2010

CONFIDENTIAL BUSINESS INFORMATION

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

SUPPLEMENTAL INFORMATION to PSNH's July 16 Letter, Response to Request for Additional Information re: BART

As requested, PSNH provides the following information to support the Merrimack Unit #2 (MK2) NOx limits for New Hampshire's Regional Haze SIP. We are providing this information as confidential business information since it contains various operating scenarios and financial costs which are competitively sensitive in nature and could be harmful if disclosed.

Merrimack Station Unit #2: Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers behind the increased costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP.

1- Operational Impacts

Based on historical data MK2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are reduced and in some instances below the SCR permissive temperature limit. The SCR temperature permissive must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and partial load operation the temperature could be lower than the permissive temperature and the SCR cannot be operated. In most cases the timing of these events is not predictable.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

A more stringent limit could result in the unnecessary shutdown of the unit rather than operating at partial load. An example of this scenario has occurred in the past when a critical pump failed which restricted full load operation. While the pump was repaired the unit remained operating but at a reduced capacity, the duration of this event was approximately 240 hours. PSNH's customers received significant benefit from this partial load operation. Replacement power costs associated with this type of event are shown in the Table 1.

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

Table 1a. Cost Associated with De-rate Flexibility at 0.37 lb/MMBtu Assumes 0.64 tons per hr				
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost	Cost per ton
240 hr	132 MW	200 MW	$1,440,000	$0
100 hr	132 MW	200 MW	$ 600,000	$0
50 hr	132 MW	200 MW	$ 300,000	$0

Table 1b. Cost Associated with limited De-rate Flexibility at 0.34 lb/MMBtu Assumes 0.59 ton per hr				
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	**Un-avoided** Replacement Power Cost	Cost per ton
240 hr	132 MW	200 MW	$1,440,000	$10,169
100 hr	132 MW	200 MW	$ 600,000	$10,169
50 hr	132 MW	200 MW	$ 300,000	$10,169

The opportunity for partial load operation during high demand periods would be even more costly to both reliability and to customers. The example mentioned above resulted in a long duration of partial load operation but it is important to note that during periods of high energy prices a much shorter event could also have significant cost. For example, assuming a $100 per MWh market price, operating at 200MW partial load for a period of 12-hours would avoid $240,000 of replacement power cost. During this period a NOx reduction of approximately 7 tons would be realized which equates to $34,000 per ton NOx. Under some of these scenarios partial load operation would be eliminated to ensure consistent compliance with the proposed NOx limit reduction.

2 – Maintenance Impacts

PSNH's highest priority is ensuring compliance with all emission limits. PSNH has reviewed historical data and concluded that start-ups, shut downs partial load operating conditions and upsets can significantly impact a calendar month average emission rate. To account for these events PSNH operates NOx control equipment to maintain a NOx emission rate of approximately 0.25 lb/MMBtu calendar month average. In order to ensure compliance with the 15.4 ton/day limit or the equivalent 0.37 lb/MMBtu emission rate, PSNH targets a 0.15 lb/MMBtu difference between the average NOx emission rate and the specific limit. Further limitations would impact operation and increase incremental maintenance and capital cost.

In addition to boiler operation and load conditions that affect SCR operation, malfunctions of the SCR system and/or associated equipment can also affect the operation of the SCR. Malfunctions of the SCR system and/or associated equipment can result in partial or complete reduction of SCR performance.

Also, as part of normal service, the SCR performance degrades overtime. One reason this occurs is due to blinding of the catalyst with fly ash. This condition will cause the SCR process control settings to compensate by increasing SCR loading to maintain the set point. This is necessary because the reagent distribution becomes less uniform as less surface area of the catalyst is exposed to the flue gas. To manage this condition from developing to the point that a maintenance outage is necessary, the SCR is cleaned on-line utilizing soot blowers and cleaned during outages, as needed. Increased SCR loading could lead to more frequent maintenance outages. It is anticipated that a minimum of three additional SCR cleanings and air heater washes would be necessary to maintain compliance with the 0.34 lb/MMBtu proposed NOx limit. Cleanings are expected cost between $30,000 and $100,000 as noted below in item 3. Replacement power costs associated with the necessary maintenance outages are also described in item 3 below.

Additionally, reagent injection grid nozzles are directly exposed to the flue gas and become fouled over time. This can affect reagent distribution, compounding the effect of blinded catalyst. The reagent injection grid is cleaned, as needed, during outages. Also as catalyst ages, it becomes less reactive. This causes a reduction in ability for NOx conversion to take place. This in itself does not typically result in higher NOx emissions because the SCR has four layers of catalyst, intentionally staggered in age. However, increased loading of the SCR catalyst would be necessary to maintain compliance with the proposed reduction in NOx limit and accelerate catalyst degradation. For example, the SCR is unable to perform continually at its maximum capability. As a result, PSNH needs flexibility to operate the SCR based on current operating conditions. Currently the SCR averages greater than 86% efficiency.

Each catalyst layer has an anticipated functional life of 8 years and each layer is staggered in age to accommodate replacing one layer every 24 –months. Further NOx limitation would increase loading of the SCR and could result in accelerated catalyst degradation requiring premature replacement. This would result in a loss of investment. Even if minor catalyst degradation occurred reducing the catalyst useful life from 8 years to 7.5 years the replacement schedule would need to be adjusted. The change in replacement schedule is necessary because catalyst replacement projects must coincide with MK2's overhaul schedule which is on a 12-month cycle. PSNH would incur a loss of investment of approximately $143,000 annually due to the early replacement. It is also important to note that the revised replacement plan would result in minimal reductions to the total reduced tons of NOx for the year, but rather be put in place to avoid the periodic increased emission rates at the end of the catalyst life. As shown below in Table 2, PSNH believes minimal catalyst replacement and maintenance cost are associated with the 0.37 lb/MMBtu rates provided certain exceptions for start-up and shutdown and malfunctions.

Table 2. Incremental Maintenance and Capital Cost				
Emission Limit (lb/MMBtu)	Calendar Month Control Target (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	0.22	$0	$0	$0
0.34	0.19	$143,000	$195,000	$338,000

3 –Replacement Power Costs associated with the Proposed Reduction in NOx Emission Rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with short-term events as described above and the operational restrictions of the SCR. Each has an additional cost as outlined below.

There will be increased maintenance costs to maintain peak NOx reduction capability. For example, air heater and SCR cleanings will be required more frequently because of increased loading of the SCR. This results in additional maintenance costs and replacement power costs associated with the required outages. It is anticipated that at least one additional 4.5 day (mid) maintenance outage would be necessary to maintain compliance with the 0.34 lb/MMBtu proposed limit. In addition to the maintenance outage additional cleaning will be completed as a proactive measure during forced outages resulting in delayed start-ups. Outage duration is from time offline until the unit is phased.

If air heater washing were completed to comply with a step change in the NOx rate as shown below, the cost per ton of NOx reduction would be extremely costly. Again this number can increase greatly if an air heater cleaning was completed during a high priced market.

Table 3. **Potential** Emission Summary (8760 hrs)		
Emission Rate Lb NOx/mm BTU	NOx tons emitted per year	Incremental reduction in **Potential** emissions tons per year
0.37	5628.34	0
0.34	5171.99	456

Maintenance (Cleaning) Costs: $30,000 to $100,000 per cleaning

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

Table 5. Impact of 0.34 lb/MMBtu Limit	
Duration of Cleaning/Outage	Replacement Power Cost per Outage
Short (3 days)	$720,000
Mid (4.5 days)	$1,100,000
Long (6 days)	$1,400,000

It should be reiterated that these compliance measures are focused solely on the shorter duration events that typically occur at lower loads with less heat input and for a discreet period of time thus do not result in the emission of a significant amount of NOx emissions. To meet the proposed rates of 0.34 lb NOx/MMBtu, under the conditions referenced above, PSNH may be forced to shutdown for air heater/SCR cleaning and also may be forced to shutdown rather than operate at partial load. Each of these aforementioned scenarios has significant cost as described above.

Also, with out exceptions for short term operational conditions additional incremental costs may be incurred when considering a calendar month averaging period. PSNH may be forced to delay start-up to maintain a 0.34 lb/MMBtu calendar month average. It is important to note that start-up shutdowns, and partial load operating scenarios may bias a lb/MMBtu rate but typical result in low tonnage emission total. To manage for this situation it may be necessary for PSNH to adjust the current operating strategy by delaying start-ups or to prevent a short operating periods during the calendar month. Table 6., below illustrates the potential cost with delaying an outage start-up.

Table 6. Replacement power cost associated with delayed start-up			
	Cost delta with the Market	Total cost of Outage for customers	Cost per Ton *
1 day	$30	$239,040	$15,936
	$40	$318,720	$21,248
	$50	$398,400	$26,560
2 days	$30	$478,080	$31,872
	$40	$637,440	$42,496
	$50	$796,800	$53,120

*assumes saving of 15 tons per day

4 - Summary of Analysis

Merrimack Station has had a program in place to reduce NOx emissions for the past 15 years. The reductions in total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable and affordable power. **It is critical to understand adjusting the NOx rate will significantly increase the incremental costs of compliance without significantly decreasing total NOx emissions.** This effort will have virtually no effect on MK2's actual emissions and is focused on limiting MK2's potential emission which results in eliminating operational flexibility and increasing operating costs. Table 7. below is a summary of the incremental costs that PSNH will incur when considering the 0.34 lb/MMBtu proposed NOx emission rate.

Table 7. Summary of Additional Predicted Annual Cost

Emission Limit (lb/MMBtu)	Calendar Month Control Target (lb/MMBtu)	Loss of Investment of SCR Catalyst per year	Un-avoidable Replacement Power cost (Partial Load) @ 240 hrs	Increase Maintenance (Cost of Air heater and SCR Maintenance) 3 per year	Replacement Power Cost For Maintenance Outage at $30 MWH	Delayed start-up to clean SCR and Air Heater 2days (One day each for two outages)	Incremental reduction in <u>Potential</u> tons per year	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	0.22	$0	$0	$0	$0	$0	0	$0	$0
0.34	0.19	$143,000	$1,440,000	$195,000	$1,100,000	$478,080	456	$3,356,080	$7,359

This analysis demonstrates that the implementation of a 0.34 lb/MMBtu or more stringent rate will result in significant cost to our customers with little environmental benefit. This is true because a lb/MMBtu rate could result in running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages, and limit partial load operation.

PSNH would be happy to meet with you and your staff to discuss the information provided above. If you have questions or require additional information, please contact Lynn Tillotson at 634-2440 or Sheila Burke at 634-2512.

cc:
Elizabeth H. Tillotson, TBM, Generation Staff
Sheila Burke, Generation Staff
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The Northeast Utilities System

December 15, 2010

Robert Scott
Director
NH Department of Environmental Services, Air Resources Division
29 Hazen Drive
PO Box 95
Concord, NH 03302-0095

Public Service of New Hampshire
Best Available Retrofit Technology (BART)
Response to Request for Additional Information

Dear Mr. Scott:

As requested in your December 8, 2010 letter, PSNH provides the following additional information to support the Merrimack Unit #2 (MK2) NOx limits for New Hampshire's Regional Haze SIP.

Merrimack Station Unit #2:

Merrimack Station was the first investor owned utility in the nation to install an SCR to achieve NOx reductions. Given the operation of the SCR, it is PSNH's position that maintaining operational flexibility is a critical priority in order to ensure continued and cost-effective compliance while simultaneously achieving significant reductions in NOx emissions. The following information summarizes the primary drivers behind the increased costs that would be incurred in ensuring attainment of NOx emissions rates lower than the current NOx emission limits set in the NH Regional Haze SIP.

This submittal will analyze the 0.30 lb/MMBtu emission rate averaged on a 30-day rolling basis as well as the impact of a more stringent limit. A 30-day rolling average is defined as the arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating day[1]. This definition is consistent with November 22, 2010 comments provided by EPA pertaining to the draft rule.

[1] *Boiler operating day* for units constructed, reconstructed, or modified on or before February 28, 2005, means a 24-hour period during which fossil fuel is combusted in a steam-generating unit for the entire 24 hours. (40 CFR 60 Subpart Da)

The summary of the analysis is provided in the following table, all supporting calculations and basis for this determination are detailed in the items below.

Summary of Analysis			
Emission Limit (lb/MMBtu)	Incremental reduction in **Potential** tons per year[2]	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	0	$0	$0
0.30	1,065	$880,000	$826
0.25 – 0.30	380	$2,888,000	$7,600

1- Operational Impacts

Based on historical data MK2 typically has 10 to 15 outages per year and approximately 8 low load operations per year. During these events, SCR operating temperatures are reduced and in some instances below the SCR permissive temperature limit. The SCR temperature permissive must be met in order for the SCR to be put in service or kept in service. During start-ups, shut-downs, and partial load operation the temperature could be lower than the permissive temperature and the SCR cannot be operated.

Examples of low load situations include, but are not limited to, the following:

- Forced and planned outage start ups and shutdowns;
- Loss of one of any equipment pair. Both pieces are necessary for full load operation and the loss of one results in half load operation (such as forced draft fans, condensate pumps);
- Loss of the main boiler feed pump;
- Loss of coal feeders, condenser waterbox cleaning, etc.; and
- Any condition which results in the flue gas temperatures to be below the SCR permissive temperature will result in the SCR not able to be put in service.

The ability to manage these events is beneficial to our customers. Adequate flexibility allows the high cost of replacement power to be minimized. Limiting operational flexibility could result in the unnecessary shutdown of the unit rather than operating at partial load. Tables 1a. and 1b. below demonstrate the replacement power cost associated with a 0.30 lb/MMBtu, 30-day rolling average emission rate. The opportunity for partial load operation during high demand periods would be even more valuable to both reliability and to customers.

[2] Incremental reduction of Potential emissions is the calculated mean of the 0.25-0.30 range.

Replacement Power Costs: The table below uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost.

Table 1a. Cost Associated with De-rate Flexibility at 0.37 lb/MMBtu Assumes 0.64 tons per hr			
Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost
240 hr	132 MW	200 MW	$1,440,000
100 hr	132 MW	200 MW	$600,000
50 hr	132 MW	200 MW	$300,000

Table 1b. Cost Associated with limited De-rate Flexibility at 0.30 lb/MMBtu Assumes 0.51 ton per hr			
Un-Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Un-avoided Replacement Power Cost
240 hr	132 MW	200 MW	$1,440,000
Avoided Cost			
Duration of De-Rate	De-rate Capacity	Remaining Capacity Online	Avoided Replacement Power Cost
100 hr	132MW	200 MW	$600,000
50 hr	132MW	200 MW	$300,000

The table is based on a steady state NOx emission rate of 0.22 lb/MMBtu and a NOx emission rate of 0.8 lb/MMBtu during partial load operation. The maximum number of days MK2 can operate in a partial load is 4.2 days (100 hrs) when considering a 0.30 lb/MMBtu 30-day rolling emission limit.

It should be noted previous submittals did not consider the rolling averaging method, because the existing Data Acquisition and Handling System (DAHS) is not configured for this averaging period. Based on EPA comments of the proposed Env-A 2300 Rule, PSNH has consulted the software vendor which supplies the DAHS and is reviewing the best available option to manage this averaging period. Current method of achieving this is through a new "Smart Reporting" software trial program. PSNH is confident in working with the vendor that the rolling average period will be achievable. Preliminary information suggests that implementing the new software has an estimated cost of $10,000 and an annual recurring cost of $2,000.

2 – Maintenance Impacts

Calendar Month Analysis (Previously Submitted):

PSNH's highest priority is ensuring compliance with all emission limits. PSNH has reviewed historical data and concluded that start-ups, shut downs partial load operating conditions and upsets can significantly impact average emission rates. PSNH's current method of operation to account for these events is to operate NOx control equipment to maintain an emission rate of approximately 0.25 lb/MMBtu calendar month average to ensure compliance with the 15.4 ton/day limit or the equivalent 0.37 lb/MMBtu emission rate. This method of operation results in approximately a 0.15 lb/MMBtu difference between the average NOx emission rate and the limit, this allows for operational flexibility as described above (i.e. start-up, shutdown, partial load operation etc). Further limitations based on a calendar month would impact operation and increase incremental maintenance and capital cost. For complete breakdown of the costs represented in Table 2a. and a calendar month analysis reference PSNH's August 16, 2010, submittal.

Table 2a. Incremental Maintenance and Capital Cost

Emission Limit (lb/MMBtu)	**Calendar** Month Control Target (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	0.22	$0	$0	$0
0.34	0.19	$143,000	$195,000	$338,000

30-Day Rolling Average analysis:

In addition to the above analysis and based on EPA comments to the draft rule and DES's request for additional information, PSNH further analyzed the impact of changing its current method which is based on a calendar month average and reviewed a 30-day rolling emission limit, as well as the incremental cost associated with this limit. PSNH agrees with EPA that the 30-day rolling average method addresses flexibility for start-up, shutdown, emergency and malfunction. However, additional flexibility is necessary to maintain short term partial load capability.

PSNH has determined that a 0.30 lb/MMBtu emission rate on a 30-day rolling average will accommodate reasonably anticipated operating scenarios while achieving approximately 20% reduction in potential emissions. The maintenance costs that will be incurred by complying with this limit is estimated to be $30,000 per year, and can be attributed to additional cleaning and inspection of the SCR and air heater. PSNH also analyzed more stringent limits and determined costs similar to those represented in Table 2a above would be incurred. The increase cost associated with a more stringent limit can be attributed to the cascading effect of increased loading of the SCR.

Increased loading of the SCR results in the following conditions each more impactful as loading increases. More detail associated with these conditions can be found in the August 16, 2010, PSNH submittal.

1) Blinding of Catalyst;
2) More Frequent Maintenance Outages;
3) Fouled reagent distribution nozzles;
4) Accelerated catalyst derogation; and
5) Loss of Investment of catalyst.

Table 2b Incremental Maintenance and Capital Cost based on 30-day Rolling Average			
Emission Limit (lb/MMBtu)	Annual Loss of Investment of SCR Catalyst	Increase Maintenance (Cost of Air heater and SCR Maintenance)	Predicted Incremental Cost
0.37	$0	$0	$0
0.30	$0	$30,000	$30,000
0.25-0.30	$143,000	$195,000	$338,000

As noted in condition 2 above there will likely be additional maintenance outages to ensure optimum SCR performance. Replacement power costs that customers would incur from an additional maintenance outage are described in Item 3.

3 – Replacement Power Costs associated with more stringent limit than 0.30 lb/MMBtu NOx Emission Rate

Merrimack Station will need to consider a number of additional compliance efforts if not provided the necessary flexibility to deal with events as described above.

Increased maintenance costs to maintain peak NOx reduction capability could be signifcant. For example, air heater and SCR cleanings will be required more frequently because of increased loading of the SCR. This results in additional maintenance costs and replacement power costs associated with the required outages. In addition to the maintenance outages additional cleaning will be completed as a proactive measure during forced outages resulting in delayed start-ups. Outage duration is from time offline until the unit is phased.

If air heater washing were completed to comply with a step change in the NOx rate as shown below, the cost per ton of NOx reduction would be extremely costly. Again this number can increase greatly if an air heater cleaning was completed during a high priced market.

Table 3. Impact of more stringent Limit	
Duration of Cleaning/Outage	Replacement Power Cost per Outage
Short (3 days)	$720,000
Mid (4.5 days)	$1,100,000
Long (6 days)	$1,400,000

Replacement Power Costs: The table uses an assumption of $30/mwhr difference between the cost of MK2 and the market cost. This number can vary greatly depending on energy market prices.

It should be reiterated to meet more stringent emission rate than 0.30 lb NOx/MMBtu, under the conditions referenced above, PSNH may be forced to shutdown for air heater/SCR cleaning and also may be forced to shutdown rather than operate at partial load. Each of these aforementioned scenarios has significant cost as described above in Table 5.

4 - Summary of Analysis

Merrimack Station has aggressively reduced NOx emissions for the past 15 years. The total annual emissions reflect that laudable effort. Going forward, Merrimack Station anticipates continuing that effort, while maximizing customer value and providing reliable and affordable power. Table 4. below is a detailed summary of the incremental costs that PSNH will incur when considering the 0.30 lb/MMBtu proposed NOx emission rate and a more stringent limit.

Table 4. Summary of Additional Predicted Annual Cost[3]

Emission Limit (lb/MMBtu)	**Un-avoidable** Replacement Power cost (Partial Load) @ 240 hrs	New DAHS Implementation	Increase Maintenance (Cost of Air heater and SCR Maintenance 3 per year	Loss of investment of the SCR Catlyst	Replacement Power Cost For Maintenance Outage at $30 MWH	Delayed start-up to clean SCR and Air Heater (Two days)	Incremental reduction in **Potential** tons per year	Predicted Incremental Cost Increase $/yr	Cost per ton
0.37	$0	$0	$0	$0	$0	$0	0	$0	$0
0.30	$840,000	$10,000	$30,000	$0	$0	$0	1,065	$880,000	$826
0.25-0.30	$1,440,000	$10,000	$165,000	$143,000	$1,100,000	$0	380	$2,888,000	$7,600

[3] Values represented in Table 4 are net values.

PSNH understand the cost per ton of complying with the 0.30 lb/MMBtu calculated on a 30-day rolling average is under the BART threshold and is willing to accept this limit, which results in approximately 20% reduction of MK2's potential NOx emissions. This analysis demonstrates that the implementation of a more stringent limit than 0.30 lb/MMBtu will result in significant cost to our customers with little environmental benefit. With running the SCR harder, more frequent air heater cleaning, extended outages, and forced outages, and limit partial load operation.

If you have questions or require additional information, please contact me at 634-2440 or Sheila Burke at 634-2512.

Sincerely,

Elizabeth H. Tillotson

Elizabeth H. Tillotson
Technical Business Manager – Generation

cc:
Sheila Burke, Generation Staff
David Cribbie, Generation Staff